Tamboran Resources

Visiting the Beetaloo

TBN hosted a site visit to the Shenandoah well

TBN last week hosted a visit to the Shenandoah South 1H (SS1H) in EP 117, which was just nearing the end of drilling, as well as showcasing the site for its planned 6.6mpta (1bcf/d) NTLNG project in Darwin. The major takeaways were that TBN has put an incredible amount of thought into maximising the value of its gas production over the coming years. The fact that it is focusing so intently on commercialisation also demonstrates the confidence it has in the geology - that it already sees this as a development play rather than appraisal. Meeting with various members of the Northern Territory (NT) Government showed the strong support that Tamboran has, and the significant benefit a development could provide the economy, with a goal to be a world class gas hub by 2030. The establishment of a NT Gas Taskforce is further evidence of the Government's commitment to supporting the sector. Travelling through the vast expanse of Tamboran's position (4.7mm gross acres) was eye-opening and the fact that it is virtually unpopulated demonstrated the lack of pushback it would encounter even though it would be a small footprint, pad drilling through the area. The high quality and high-tech drilling rig was impressive and should lead to lower cost, higher efficiency drilling, which is already evident from the SS1H well.

Series of announcements in strong push towards Beetaloo commercialisation

The main catalysts we see in the coming months are the fracing of the SS1H well with an expectation of 30-day initial production ("IP30") flow rate of >2.5mmcf/d (well above the commerciality threshold) in Q1'24 for the 500m section; a work-over of the A2H well to increase flow rates and the drilling of the A3H well. 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 2024: TBN believes this trend could contain 17tcf of recoverable gas and SNV1 could allow this to be booked as 2C resource. TBN requires further funding for its 2024 programme and we see various ways to raise money whilst minimising dilution. Options include a pre-payment for gas sales, debt financing, a US listing in early 2024 or a farm-down of some of the assets.

Potential for TBN to be one of the largest global independent gas producers

TBN provides exposure to the robust pricing dynamics of Australia's increasingly gas-short market due to depleting resources, with a significant gas potential of approximately 150tcf (>25bnboe) in net recoverable prospective resources in one of the world's most promising shale gas basins. The Beetaloo Basin exhibits characteristics comparable to the best shale gas wells in the United States. While there is minimal risk concerning gas availability given prior drilling, the focus is on the economic viability of extraction, showing promising early results. The Beetaloo's favourable rock properties should enable highly profitable flow rates and well recoveries, particularly within Tamboran's core-acreage. Crucially, TBN has established numerous pathways for commercialising its gas, enhancing its value. Backed by a team with extensive technical expertise in U.S. shale plays and a history of early-stage E&P success, we believe Tamboran is well-positioned to produce cost-effective gas in Australia and market it as net-zero emission LNG at premium prices in Asia.

Valuation: 400% upside to our risked NAV of A$0.71/sh

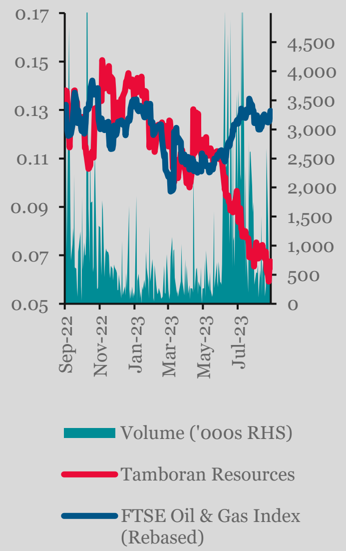
Our risked NAV of A$0.71/sh is based on our long-term Brent forecast of US$70/bbl flat (implied L.T. Asian LNG price of US$10.5/mcf at 15% of Brent). On an unrisked basis we have a NAV of A$4.62/sh or ~25x upside for the development of 15tcf net to TBN. At an NPV10 of A$0.5/mcf, TBN's market cap is pricing in a development of only 0.25tcf out of the ~150tcf of prospective unrisked net gas resource. TBN is looking to sanction a Pilot Development in 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 40mmcf/d aimed for end-2025, before it aims to add a further 5tcf of net 2P reserves. At the end of the decade, it aims to produce 1.5bcf/d of gross gas, which would generate US$4.4bn in gross revenue at US$8/mcf netback.

GICS Sector	**Energy**
Ticker	ASX:TBN
Market cap 18-Sep-23 (US$mm)	149
Share price 18-Sep-23 (AUD $)	0.14

NAV summary (AUD c/sh)

Asset	Unrisked	Risked
Cash & other	3	3
EP 136	220	14
EP 98	190	43
EP 161	55	10
Total NAV	**468**	**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.

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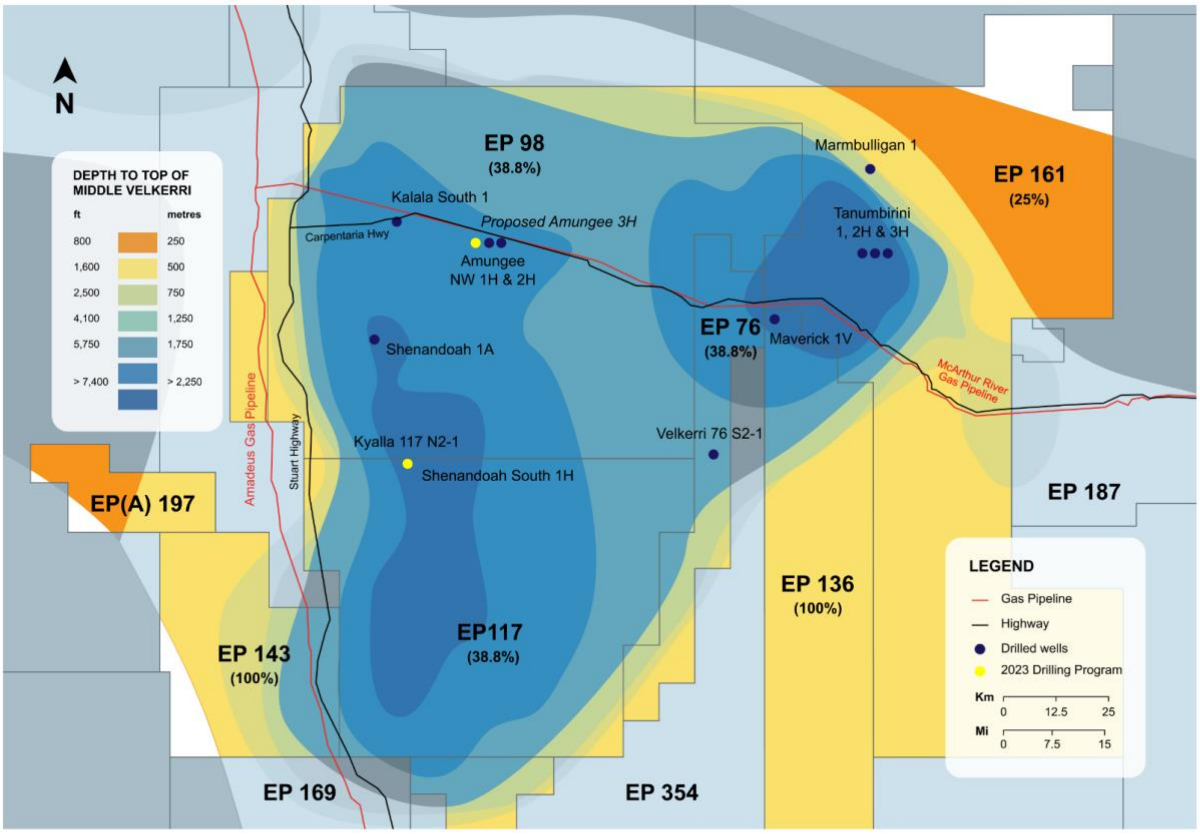
Investment case

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, it offers exposure into global and especially Asian LNG markets, where prices are well above the expected full cycle break-even from the Beetaloo. Tamboran's exploration assets have huge gas potential (~150tcf or >25bnboe of net recoverable prospective resources) 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

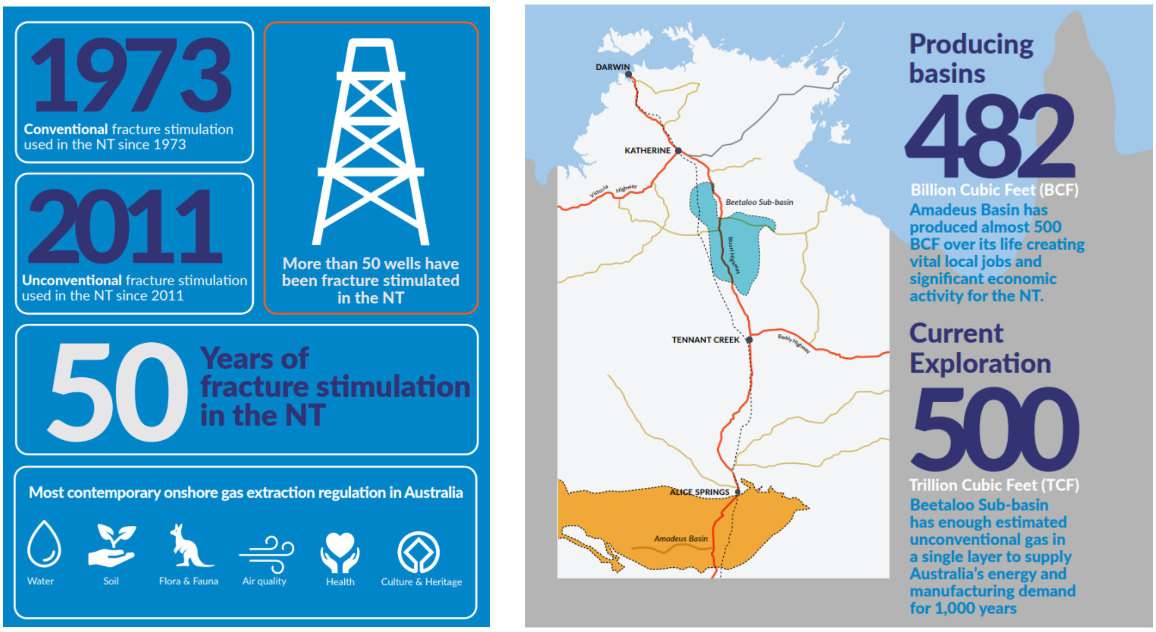
The Beetaloo's properties and wells to date suggest excellent quality rock, allowing highly economic flow rates and recoveries per well with Tamboran's acreage located in the core of the basin. Crucially Tamboran has lined up multiple commercialisation pathways for the gas, which is key to value creation. 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; LOIs with six of Australia's largest and most reputable energy companies; 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 Group 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.

Site visit takeaways

Supportive Northern Territory 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 and Tamboran was awarded up to A$7.5mm 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 stated.

Onshore natural gas fracture stimulation and Basins in the Northern Territory



Source: Northern Territory Government

One of the key factors for a successful development is to have local buy-in to the project - many resource industry projects have failed to deliver on the back of lack of community engagement and Government support. The Northern Territory is a state that has little in the way of natural resource and industry so the prospect of a large gas development is something that could make a meaningful difference to the region bringing jobs, tax revenue and economic growth. This is further enhanced by the plans for a net zero Scope 1 and 2 development.

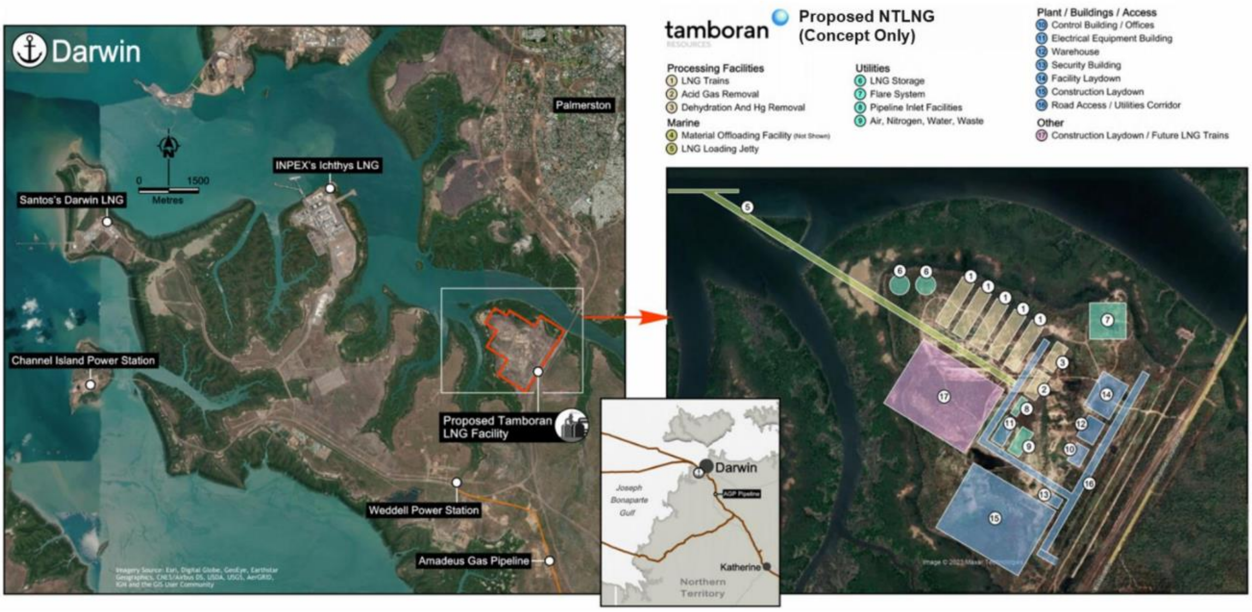
The benefits could be sizeable with >A$220mm increase in real net income for NT and the creation of >13,000 jobs including indirect employment, which is significant given a population of <250,000. TBN estimates >A$3.5bn in additional revenue for the NT Government and Traditional Owners over 25-years.

Tamboran has been working hard on community support and engagement to educate on the benefits its developments could bring and also demonstrating the low impact of the drilling and development activity as well as destroying some of the myths that surround fracking. In the NT, the independent Scientific Inquiry into Hydraulic Fracturing found that risks could be sufficiently mitigated if all 135 recommendations (that became 138) were implemented. All have been implemented to create a new regulatory environment.

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.

Ambitious Middle Arm Project

NTLNG



Source: Tamboran

We had the opportunity to sail out to see the existing Darwin and Ichthys LNG projects and site for the proposed Tamboran LNG facility as part of the Middle Arm development.

The Middle Arm project is a vast and ambitious project planned by the NT Government that would see tens of billions of dollars invested into multiple industries. A lot of thought and pre-planning has gone into the project to best use the strategically located land next door to the existing Ichthys and Darwin LNG facilities. As well as the potential for multiple trains of LNG, there has been land allocated for ammonia, urea/methanol/phosphate/ethylene production.

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 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 CO2 natural gas supply. The Government has granted A$1.5bn for middle arm predominantly for the dredging component. A key benefit of the NT leading the project is that it will lead to pre-approvals on environmental impact assessments saving significant time and money for Tamboran. The Environmental Impact Study ("EIS") for the Middle Arm is expected to be completed by the NT Government in Q1'25 with work starting on the project in 2025.

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 would not be 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.

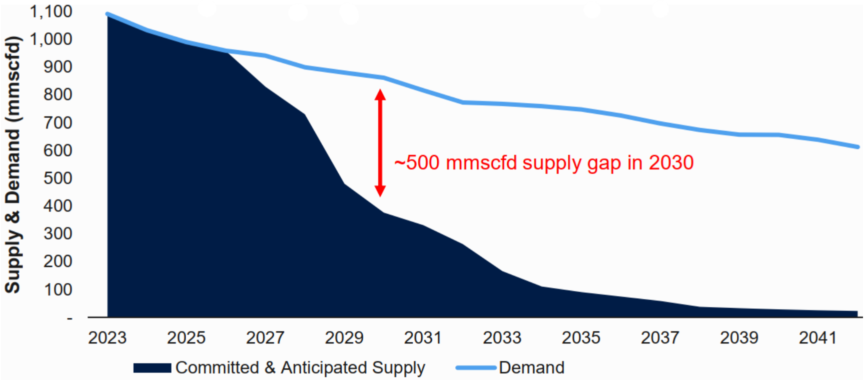
Northern Territory and East Coast likely to be short gas

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 New South Wales. 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.

Tamboran has strategically positioned itself to maximise the value of its gas. This approach provides flexibility, enabling it to avoid being locked into a single project and fostering competition for its gas. Given the increasing strategic importance of gas in Australia, as evidenced by recent high-value asset transactions and impending domestic shortages, TBN's substantial Beetaloo gas resource, both in terms of size and location, holds the potential to be a game-changer.

TBN possesses a multitude of options for monetising its gas in the medium to long term, which is especially valuable considering the limited alternatives for new Australian supply. The East and southeast regions of Australia exhibit significant domestic gas demand, while LNG facilities on the east coast require additional gas supplies. Furthermore, there are opportunities for brownfield and greenfield expansion in the Darwin area, further enhancing TBN's potential in the gas market.

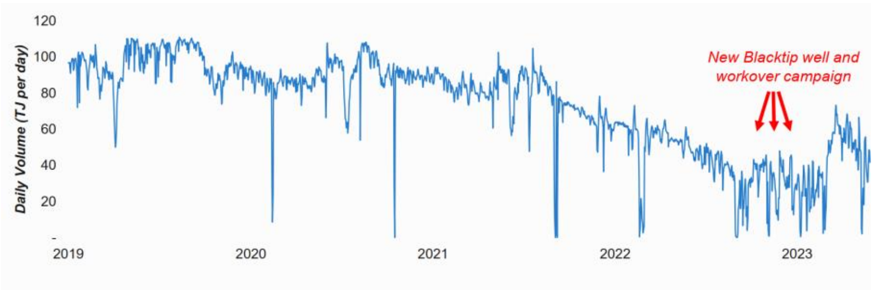
Forecast East Coast Gas Supply & Demand (assuming no gas diverted from LNG exporters)



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

The east coast gas market will be facing a severe supply shortfall in a few years as existing supply declines and the lack of new supply options. The shortfall is forecast at 450mmcf/d in 2028, therefore TBN intends to commence large scale gas sales into the market at 500mmcf/d starting end-2028 and has already signed LOIs which total 600-875mmcf/d with 6 buyers.

Declining Blacktip production impacting NT gas market



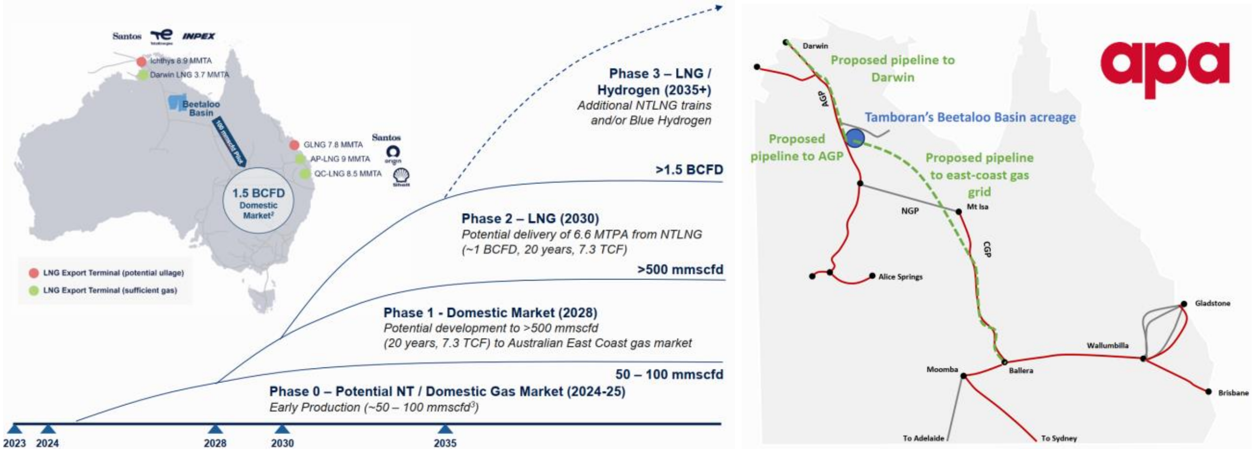
Source: Tamboran

Given the expected gas shortfall in the local Darwin market, TBN has pivoted on its near-term pilot development to supply Darwin rather than the East coast via the McArthur Pipeline. The NT domestic market consumes 50-65TJ/d of gas mainly for power generation. Currently, the existing gas supply comprises ~50TJ/d sourced from Eni's Blacktip field, along with an additional ~25TJ/d from the Mereenie and Palm Valley fields. Any surplus gas is directed to Mt. Isa through the Northern Gas Pipeline, which runs from Tennant Creek to Mt. Isa.

Blacktip underperforming (declining faster than originally expected) creates opportunity for further supply and there is the opportunity for Tamboran to meet the shortfall in 2025. Government-owned Power and Water Corporation (PWC) has a 25-year contract from Blacktip, expiring in 2031, and is seeking new supply to replace anticipated shortfall.

Many commercialisation pathways

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



Source: Tamboran

Strategic infrastructure potential supports growth to >1.5bcf/d

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.

The signing of a deal with APA as an infrastructure partner has two major implications: first the capacity will unlock significant potential gas output that TBN can send down the pipeline to a region with a deeper pool of consumers, 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 50mmcf/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.

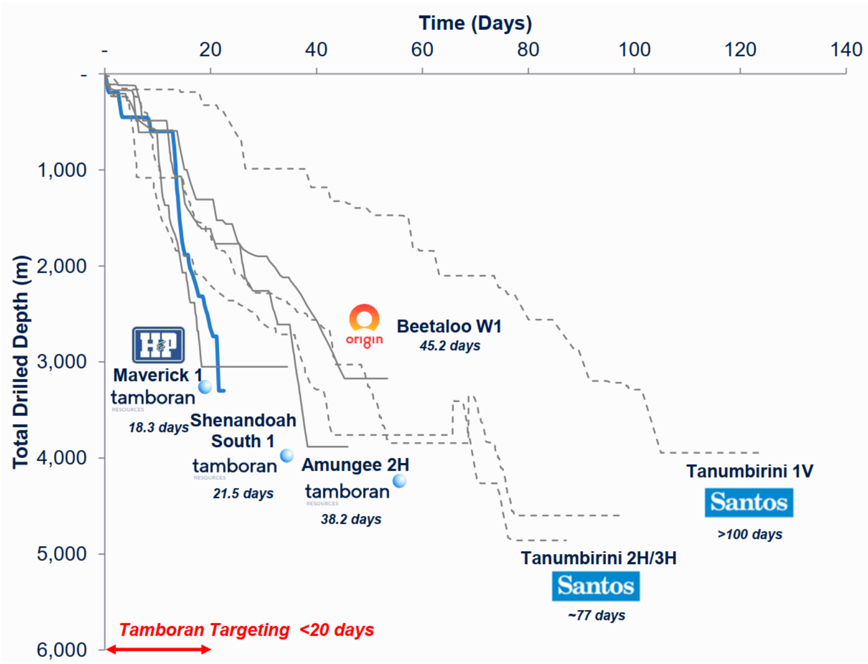
Net zero project in line with new Safeguard legislation

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 CO_2 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. The new "Safeguard regulations" establish that new shale facilities have a "zero" GHG baseline i.e. net zero scope 1 emissions.

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.

Impressive modern rig with enhanced drilling performance

Latest wells proving operational capability and transfer of US shale technology



Source: Tamboran

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 the ability to reduce development footprint and environmental impacts. The signing of a two-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.

Helmrich & Payne rig drilling SS1H well

Source: Hannam and Partners

The latest wells are proving operational capability and transfer of US shale technology. SS1H drilled 3,300 metres in 21.5 days, a daily average record with hole size suited to run 5 ½ inch casing. Helmrich & Payne 's highly advanced FlexRig® Flex 3 rig has already ushered in a significant improvement in drilling efficiency. Notably, during the drilling of the SS1H pilot hole, it achieved an unprecedented drilling speed of 80 meters per hour. This achievement was made possible by leveraging insights gained from the drilling of Tanumbirini 2H and 3H, in which TBN holds a 25% working interest while Santos operates with a 75% interest. The deployment of cutting-edge U.S. drilling technology, including specialized drilling bit design, played a pivotal role in this achievement. Tamboran is now setting its sights on completing future 3,000-metre horizontal wells in less than 20 days using the super spec FlexRig® Flex 3 rig.

Many options to finance to first gas sales

To achieve remaining activities necessary to firm-up a potential Flare Avoidance Project and book ~7 TCF (net) 2C gas resources, Tamboran will require US$50-70 million of capital in the future. There are several capital levers to supplement future equity:

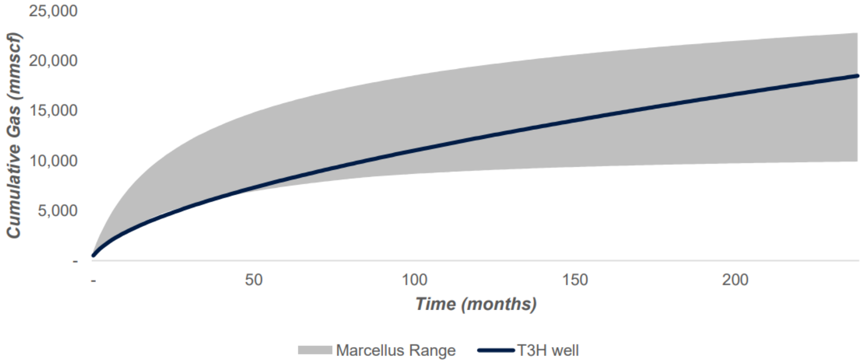
- Gas sales pre-payment: Based on selling ~40TJ/d of gross gas, we estimate that this will generate net revenue of ~A$50mm per annum at a A$10/mcf gas price. Therefore, there is the potential to raise up to A$100mm if it can secure a 2 year pre-payment.
- US listing: Potential to source deeper pool of capital in US with deep understanding of shale developments. We believe that this would make sense given the deep understanding of shale plays in the US and highly respected major US shareholders in Tamboran. We believe a listing is possible as early as Q1’24.
- Farm-in: If the results of the SS1H well are successful, this should be an attractive entry point for a farm-in partner.
- Royalty transaction: Tamboran is actively evaluating an opportunity to raise funds through sale of a royalty over Tamboran’s Beetaloo Basin acreage.

- Debt: Potential to raise debt from financiers to support development of the proposed pilot development.

Tanumbirini results have derisked the play

The of Tanumbirini 2H (T2H) and 3H (T3H) wells drilled by Santos demonstrated commercial flow rates and are supportive of higher pressure leading to higher flow rates, which is positive for the Shenandoah area. Modelling of T2H and 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.

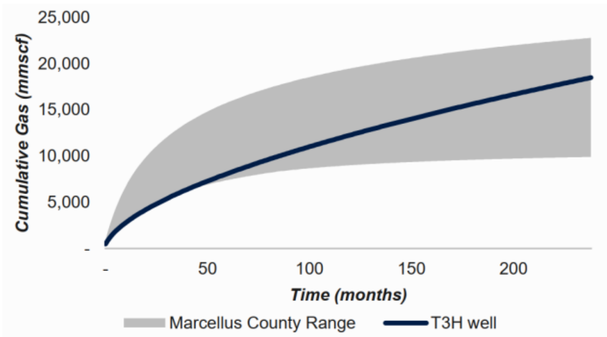
The Tanumbirini 3H well shows 20-year cumulative gas volumes in line with the Marcellus type curve set (Marcellus type curves by county – extrapolated to 3,000-metre stimulated lateral length)



Source: Tamboran

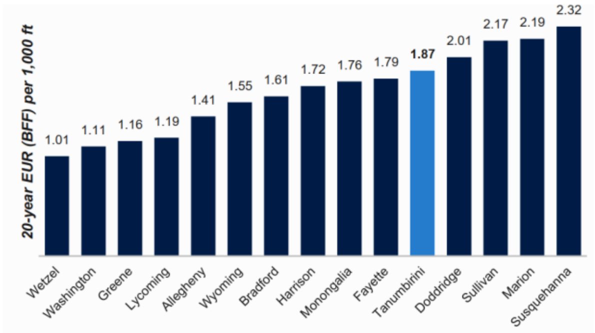
Being the first two wells drilled in the deeper 'Core' Beetaloo Basin, Tamboran believes that significant improvement in flow rate and EURs can be established with application of learnings to optimise stimulation design. The Tanumbirini wells deliver stable, long-term flow rates over a 20-year period 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 is often associated with higher gas saturation and permeability.

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

High confidence in performance of SS1H well

Testing demonstrates greater well productivity at depth within Beetaloo Basin: IP30 flow rates (mmcf/d)

Source: Tamboran

Shenandoah South 1H (SS1H) in EP 117 targeted the Mid Velkerri "B Shale" is ~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 demonstrates the enormous productivity within the deeper regions of the Beetaloo Basin.

To date the SS1H well has intersected a thicker than expected shale sequence with higher porosity and gas saturation relative to offset wells. The well was drilled at the fastest rate per day for Beetaloo Basin well going sub-3,000m and reached a maximum speed of 80m/h. This gives confidence for future wells taking <20 days. TBN is preparing to undertake 10 stage, 500-metre stimulation program at SS1H during Q4 2023. The SS1H well IP30 flow test is planned for early 2024 and on success would allow the booking of initial 2C resource. TBN targets sanction of proposed ~40mmcf/d Pilot Development on demonstration of commercial rates at SS1H. APA is to construct proposed pipeline from Shenandoah South location to Amadeus Gas Pipeline (AGP)

Work-over of A2H well expected to improve flow rate

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.

The result was clearly not what was expected but TBN is very confident that it was not a geological issue. The confidence is demonstrated by TBN going back to drill another development well at Amungee. The possible "skin" preventing higher gas flow is thought to be because of bacterial formation as the frac water was left too long and not sufficiently treated - a key learning for future wells. The well results so far have provided plenty of learnings that can be taken and used to improve the completion design of future wells.

Modelling indicates that the 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 by initial results from the laboratory which 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. TBN expect to improve the flow rate through various clean-up activities in Q4'23.

Amungee-NW1H well by Origin/Falcon suggested a flow rate of 5.5mmcf/d per 1,000m of lateral.

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 are introduced during drilling operations which interact with the fluids and rock formation in the wellbore. Bacterial activity can lead to the production of metabolic by-products, 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 be 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.

Strong operational and management team

We had the opportunity to spend time with the senior leadership team and the operating team. 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.

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 (Coal Bed Methane) 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. Furthermore, TBN's 17% shareholder and owner of its partner in the assets, Bryan 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.

Valuation

400% upside to our risked NAV

Asset	Gross bcfe	Interest	Net bcfe	NPV A$/mcfe	Unrisked A$m	Unrisked A$/sh	Geological CoS	mmercial CoS	Risked A$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.

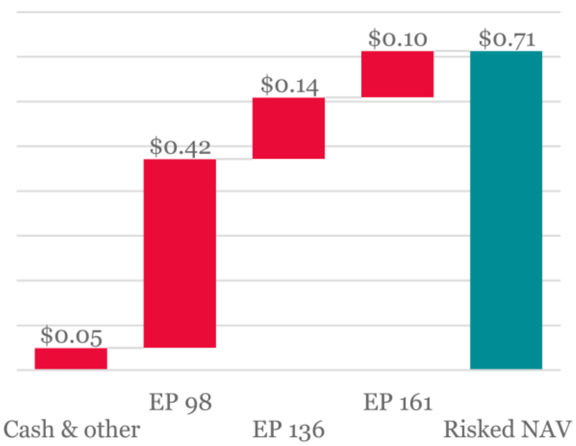
We add in a further 1bcf/d of net production of gross production based on production going to the East coast LNG plants through a new 1bcf/d pipeline. We assume 50% or 0.5bcf/d goes from TBN's 100% owned EP 136 asset (worth A$2.16/sh unrisked; A$0.14/sh risked) and the other 50% from TBN's 25% owned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

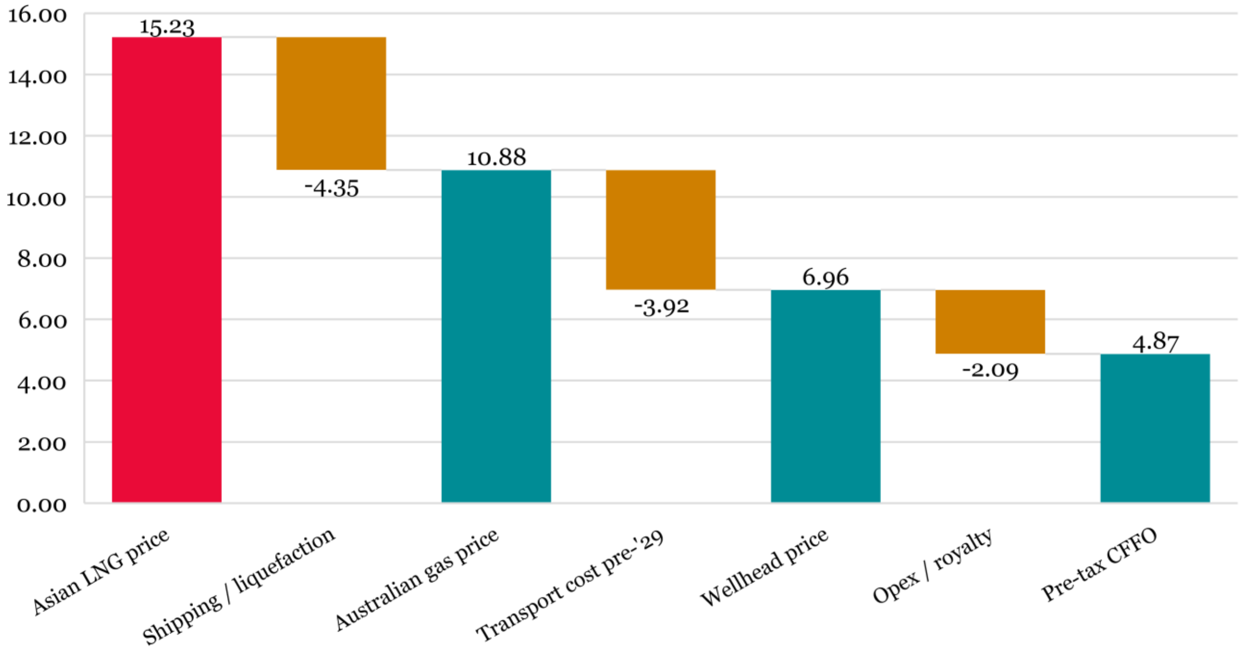


Source: Company reports, H&P estimates

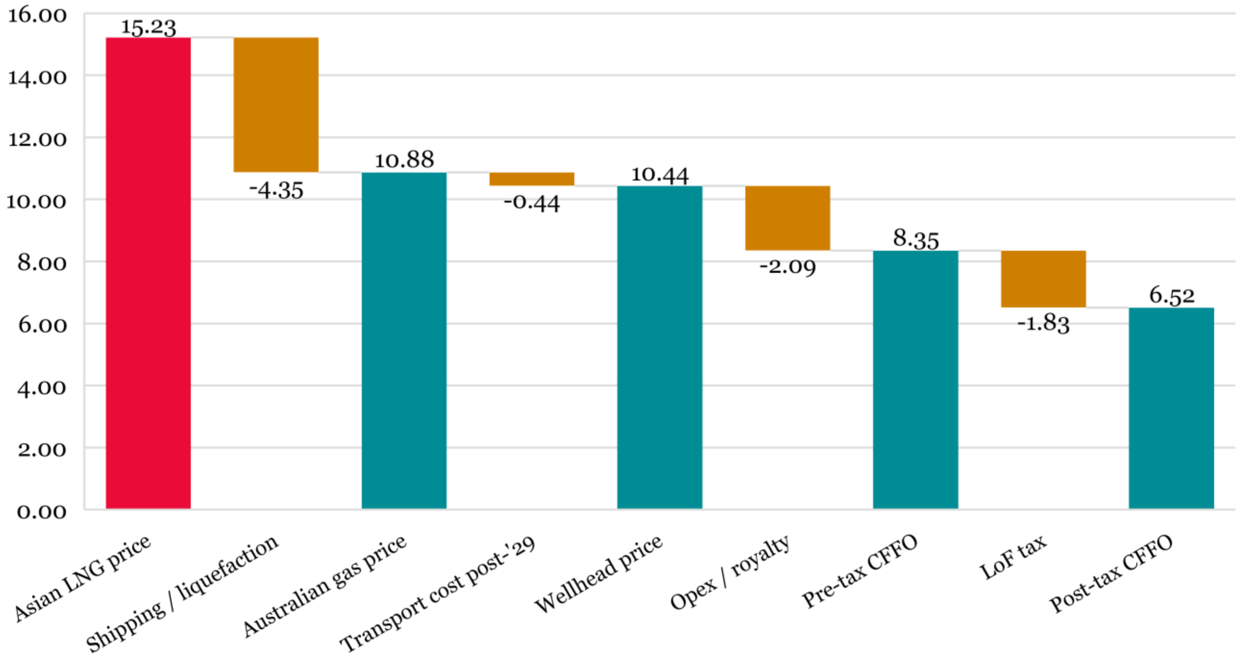
Gas prices and realised prices

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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