Tamboran Resources

Core position in a potentially world class shale play to supply net zero gas

We initiate coverage on Tamboran with a risked NAV of A$0.79/sh

Tamboran Resources (ASX: TBN) is an E&P company focused on unconventional gas in Australia, which listed in July 2021. Its assets are in the Beetaloo Sub-basin in the Northern Territory and contain net unrisked prospective resources of ~31tcf of gas. It has a focused strategy on developing clean, low cost, natural gas. Tamboran offers exposure into the positive pricing dynamics of Australia's gas market and indirect exposure into global and especially Asian LNG markets. Tamboran's exploration assets have huge gas potential in one of the most promising shale gas basins globally, with the characteristics to match the best shale gas wells in the US, 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. Tamboran's team has deep technical knowledge of US shale plays and a track record in early-stage E&P success. Tamboran could produce some of the lowest cost gas in Australia and monetise it at premium prices in Asia, as net zero emission LNG. Its recent IPO means it is well funded over the next year.

Beetaloo: 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 to be the most prospective shale play in the world. Although unconventional oil and gas plays exist in many regions globally, very few have all the elements in place, particularly from a commercialisation perspective. 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.

Beetaloo play de-risked, infrastructure deal in place & supportive Government

The Beetaloo play has been de-risked by Tamboran's first vertical well, which when converted to a lateral well implies 15-20mmcf/d potential per well. Also, a recent well test on the nearby Amungee-NW1H well by Origin/Falcon suggested a flow rate of 5.5mmcf/d per 1,000m of lateral (double what we estimate is required for commerciality). Tamboran has signed an MOU with infrastructure company Jemena Ltd to build a 1bcf/d pipeline from the Beetaloo to access the East coast domestic gas and LNG export market to sell its gas. There is a supportive Government, demonstrated by recent incentives put in place. 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.

Catalysts: key well results expected before the end of the year

We see the key catalysts as the flow test results from the T2H and T3H wells in Q4'21. A commercial rate would not only de-risk the EP 161 block, in which Tamboran has a 25% JV interest, but also the adjacent, 100%-owned EP 136 block, where drilling is planned in 2022 with the Maverick #1H well. There is potential read across from other wells in the basin, such as Falcon's Amungee and Velkerri wells, which could provide further confidence in the play. From a commercialisation standpoint, the formalisation of an infrastructure deal with Jemena would be an important de-risking event. There is also the possibility of a farm-out of its acreage over the coming year.

Valuation: our risked NAV implies 132% upside to the current share price

Our risked NAV is A$0.79/sh which comprises A$0.50/sh from EP 136, A$0.23/sh from EP 161 and a further A$0.06/sh in net cash less G&A etc. On an unrisked basis we have a NAV of A$2.11/sh or >5x upside for the development of 3.5tcf net to Tamboran. At our NPV10 of ~A$0.4/mcf, TBN shares are pricing in a development of just 0.5tcf of resource. Falcon's farm-down to Origin at the market's nadir in April 2020, implied a value of ~A$335mm (~150% higher than Tamboran's EV) for its gross contingent resource of 6tcf, which is only ~20% of Tamboran's net prospective resource.

GICS Sector	**Energy**
Ticker	ASX:TBN
Market cap 29-Sep-21 (US$mm)	162
Share price 29-Sep-21 (AUD $)	0.34

NAV summary (AUD c/sh)

Asset	Unrisked	Risked
Cash & other	6	6
EP 136	164	50
EP 161	40	23
Total NAV	**211**	**79**

Source: H&P estimates

31tcf

Tamboran's unrisked net prospective gas resource.

Net zero CO_2

Tamboran has committed to produce natural gas with zero Scope 1 and 2 emissions.

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Investment Case

Company overview – Tamboran Resources Limited (ASX: TBN) is an E&P company that is focused on unconventional gas in the Northern Territory, Australia. Tamboran's key assets are a 25% working interest in EP 161 and a 100% working interest in EP 136, which are in the Beetaloo Sub-basin and contain net unrisked prospective resources of ~31tcf of gas. Tamboran was founded in 2009 and listed on the ASX in July 2021. It has a focused strategy on accelerated commercialisation of clean, low cost, natural gas from the Beetaloo Basin. Once it builds up its proprietary knowledge of the basin it could expand further within the basin or to other areas, such as the Canning Basin in Australia.

Investment proposition – Tamboran 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 (~31tcf of net recoverable prospective resources or >5bnboe) 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. 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 is partnered with Santos, a major global LNG player with its own operated LNG facilities within range of the basin and has signed an MOU with infrastructure company Jemena Ltd 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.

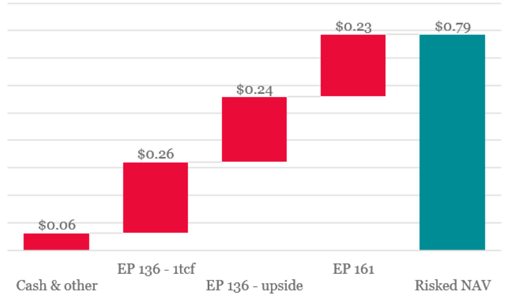
Valuation: 132% upside to our risked NAV – Our risked NAV is A$0.79/sh, which implies 132% upside from the current share price. On an unrisked basis we have a NAV of A$2.11/sh or >5x upside for the development of 3.5tcf net to Tamboran. At our NPV10 of ~A$0.4/mcf, Tamboran is pricing in a development of just 0.5tcf of resource. Falcon's farm-down to Origin last year, at the market's nadir in April, implied a value of ~A$335mm (150% higher than Tamboran's EV) for its gross contingent resource of 6tcf, which is only ~20% of Tamboran's net prospective resource.

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

		Net recoverable resource (tcf)				
		0.5	1.0	2.5	10.0	31.0
	$0.05	0.10	0.14	0.25	0.81	2.37
NPV	$0.25	0.25	0.44	0.99	3.79	11.61
$/mcf	$0.40	0.36	0.66	1.55	6.02	18.54
	$0.50	0.44	0.81	1.93	7.51	23.16
	$1.00	0.81	1.55	3.79	14.97	46.26

Source: H&P estimates

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

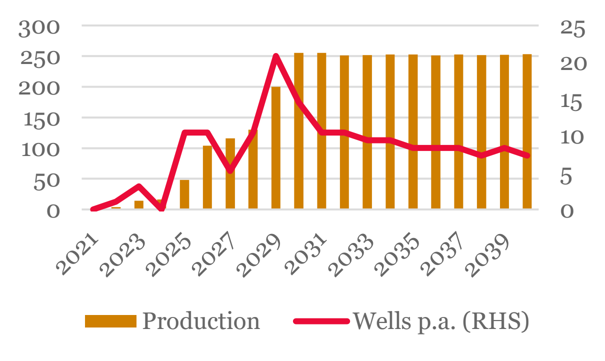


Source: Company reports, H&P estimates

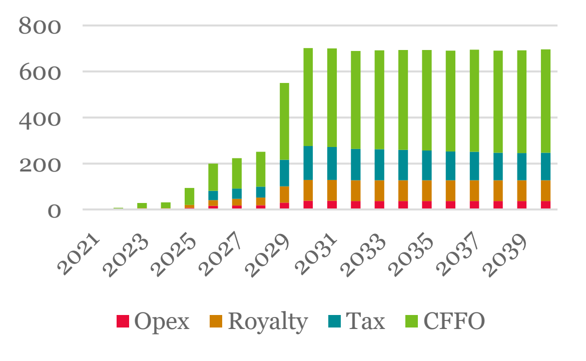
All the elements in place for a successful shale development - We believe that the Beetaloo is well positioned to be successful given the geology and other commercial considerations. As the source rocks are much thicker than comparable US shale plays, there is potential for world-class resources, and the Beetaloo is considered by many to be the most prospective shale play in the world. 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. This is reflected in Tamboran honing in on the Northern Territory in Australia and relinquishing its assets in South Australia, Western Australia, Turkey, Myanmar, the UK, Northern Ireland and Botswana.

Beetaloo Play has been de-risked with Tamboran in the core - Tamboran 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. An independent reserve report has confirmed that the first vertical well on EP 161 has proved up 117bcf of recoverable gas (2C resource) with an upside case (3C) of 265bcf (~45mmboe). The first vertical well that was drilled and tested implies that, when converted to a reasonably sized lateral well, there could be 15-20mmcf/d potential per well. Also, a recent well test on the nearby Amungee-NW1H well by Origin/Falcon suggested a flow rate of 5.5mmcf/d per 1,000m of lateral. Our scoping economics suggest that a flow rate of around half this amount would still be economic. In our base case we assume 4.5mmcf/d per 1,000m and 12.5bcf recovery per well (EUR), which gives an NPV10 of ~A$0.4/mcf. Also the Amungee NW-1 well only had half the thickness of M Velkerri 'B' compared to Tanumbirini 1.

EP 136: 250mmcf/d production scenario and wells



Split of revenue (A$mm)



Source: H&P estimates

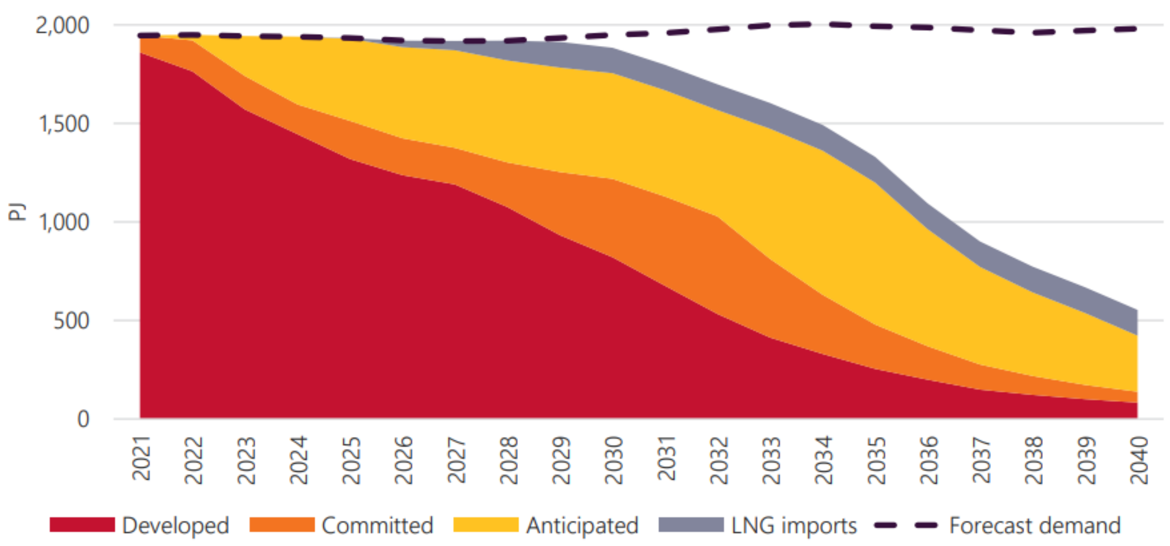
Strategic infrastructure potential supports growth to 500mcf/d – Tamboran has signed an important deal with infrastructure company Jemena to build a 1bcf/d pipeline from the Beetaloo to access the East coast domestic gas and LNG export market. This has two major implications, first it means that Tamboran as a partner with Jemena will have access to significant capacity of up to 500mmcf/d 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 Shell selling a stake in its QCLNG common facilities and TOTAL announcing a US$750mm sale and lease back deal on its GLNG plant, both with GIP Australia on the East coast. There is the potential for Tamboran to reach 100mmcf/d of net production in 2025 and 500mmcf/d by the end of the decade supplying either the East Coast or Darwin/Ichthys LNG

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. In the Beetaloo, several big companies like Santos and Origin Energy are in the early stages of exploration, alongside smaller players like Empire, Falcon and 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. 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 last September. A recent Australian Competition and Consumer Commission (ACCC) report has identified the Beetaloo Basin as a priority development to address anticipated domestic gas shortfalls by 2024. 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.

Projected eastern and south-eastern Australia gas production (including export LNG), Central scenario, existing, committed, and anticipated developments, 2021-40 (PJ)



Source: AEMO

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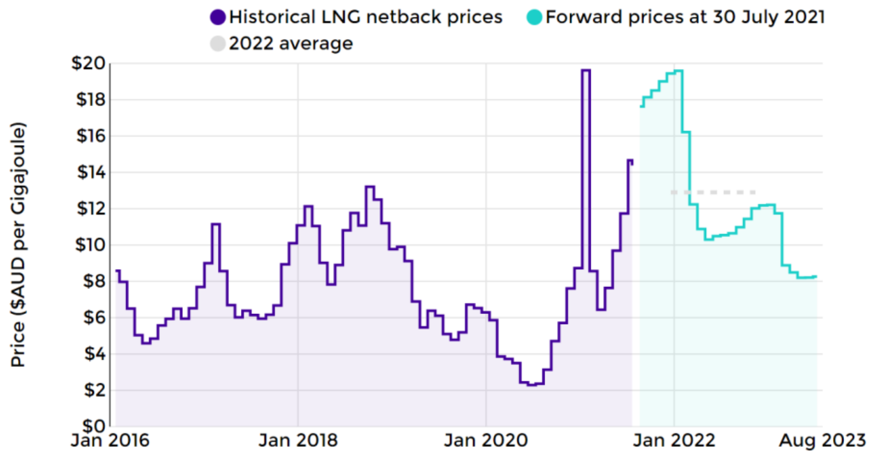
Australia becoming increasingly short gas - The growth in LNG exports has resulted in higher natural gas prices and concerns of domestic natural gas shortfalls, particularly on the east coast of Australia. The country's first LNG import facility has also been approved for NSW. The Government established 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 at 30th July 2021



Source: ACCC

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 more recently the delay of many planned LNG liquefaction facilities globally. The impact of this has been seen in 2021 with mid-year gas prices reaching record levels (e.g. European gas prices reaching >US$25/mcf and Asian LNG ~US$30/mcf) well before winter. 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.

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. 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.

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 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.

Investment risks – Other than the general risks facing energy companies, the key specific risks that we see facing Tamboran are unsuccessful wells from its 2021 drilling campaign either through disappointing geology or drilling issues (this is mitigated by the extensive technical work and US shale drilling experience of the team). On EP 161, Tamboran is does not have operational control so there is a risk that the operator Santos focuses elsewhere, slowing the development potential; however, Tamboran has its own 100% owned block EP 136 where it is in control of its own destiny. The key commodity price risk to which Tamboran is exposed is Australian gas pricing, although the expected low cost of production means that the Beetaloo play could potentially work at depressed prices in case of a severe deterioration in the gas market. Also, Tamboran will require further funding for the appraisal and development of its acreage from 2023, which means there is the risk of equity or asset level dilution, although farming down after the drilling campaign is part of Tamboran's strategy. A key risk in the success case of proving up substantial commercial reserves is an inability to transport the gas from the remote Beetaloo basin to an end-user market; this has been addressed through the signing of an MoU with Jemena to build a pipeline to access the East Coast gas market. There is regulatory risk in Australia that a change in regulations either on fracing or the gas market will impact Tamboran's economics; however, the current emphasis from the Government is solving the potential gas shortfall in Australia in the coming years. Also there was a Northern Territory fracing moratorium and rigorous scientific enquiry that took place, following which the fracing ban was lifted.

Catalysts

There are various catalysts that we see potentially impacting the equity story over the coming year.

- **EP 161: Tanumbirini #2H and #3H well results** - The Santos and Tamboran joint venture (EP 161 JV) are drilling two exploratory wells on EP 161 in 2021. #2H was spudded in May and drilling was completed in August. #3H well is currently being drilled. The wells are then expected to see 10-20 stage fracs and the partners should conduct flow tests with initial and 180 day test results being investigated. Preliminary flow test results from T2H and T3H are anticipated to be available in Q4'21.

- **EP 161: Inacumba #1H and #2H** - Depending on the results from 2021, Santos and Tamboran may drill a couple of follow-up horizontal wells on EP 161 and flow test them in 2022. These step-out wells have the potential to expand the area of de-risked reserves.

- **EP 136: Maverick #1H well** - This horizontal well is planned for 2022 on block EP 136 where Tamboran has 19tcf of unrisked prospective resource. Success here will allow Tamboran the opportunity to control the pace of development of this asset that it owns 100%. If Maverick ~1H is successful, Tamboran intends to drill up to 3 wells in EP 136 during 2023, which will allow it to move towards early commercial production of 10-20mmcf/d.

- **Origin/Falcon's Amungee NW-1H well –** In September, Origin/Falcon announce a normalised gas flow rate equivalent of 5.2-5.8mmcf/d per 1,000m of lateral from the Amungee NW-1 well into the Velkerri B shale formation, which has a positive read-through into Tamboran's acreage. The extended production test at Amungee is continuing with further results to come.

- **Origin/Falcon's Velkerri 76 well** - Although Tamboran is not involved in this well it is located in the core of the Beetaloo, around 30km southwest of Tamboran's planned Maverick #1H well. A vertical pilot well was spudded in August to acquire, core, run logs and perform a diagnostic fracture injection test across the Velkerri. Tamboran will also have access to the data which will help it de-risk part of its acreage.

- **Empire exploration programme** – Empire's Carpentaria-1 vertical well was fracture stimulated and flowed at a peak rate of 1.6mmcf/d and average rate of 0.25mmcf/d before being shut-in due to COVID. Empire was finalising preparations to restart flow testing operations at the Carpentaria-1 vertical well in late September. This well is located toward the edge of the basin to the east of Tamboran's blocks.

- **Equity raisings, asset sales or farm out arrangements** - The EP 136 and EP 161 follow-on campaigns are reliant on some form of fund raising.

- **Overriding Royalties and Area of Mutual Interest Obligation** – The assets acquired from Sweetpea are subject to overriding royalty interests (ORRI) and an Area of Mutual Interest (AMI) obligations giving certain holders a share of the revenues/profits from the assets. Tamboran has the option to make cash payments over the coming years to reduce the future obligations once production starts.

- **Formalisation of infrastructure deal with Jemena** - Pursuant to the MoU, Tamboran and Jemena are proposing a new company known as the Jemena Tamboran Joint Venture (JTJV). JTJV provides a formal framework and infrastructure solution to bring Tamboran's gas resource to market.

- **Expiry of shareholder lock-ups** - ~55% of shares are currently locked up following the IPO for a period of up to 24 months. Once the lock-ups expire there will be the positive of additional trading liquidity but also the risk of existing shareholders selling down into the market.

Company Overview

Tamboran Resources Limited is a public, gas-focused E&P company with its main operations set in the Northern Territory of Australia. Tamboran was founded in 2009 and is headquartered in Sydney. It is 100% Operator of EP 136, EP 143 & EP 197(A) and 25% JV Partner with Santos in EP 161. In total it has net unrisked prospective resources of ~31 Tcf and has invested more than A$50mmin drilling activities to date.

In the short-term, the company's focus is to de-risk the substantial prospective resources that have been identified in the Beetaloo/McArthur basin. Subject to a successful seismic, drilling and testing program, Tamboran aims to provide affordable gas to local Northern Territory markets by 2023-2025 and to supply gas to the east coast of Australia by 2025, to meet material forecast domestic gas shortfalls. In the longer run, it aims to provide backfill gas to existing Australian LNG developments to meet the increasing demand for gas in SE Asia.

Key Licences

- **EP 161** - On 11 December 2012, Tamboran entered into a farm-in agreement and a joint operating agreement for EP 161 with Santos (Tamboran with a 25% stake and Santos holding 75%). The block spans north-south with varying widths having a total area of approximately 10,500 km^2. The amount of prospective fairway acreage in EP 161, estimated from fairway maps published in 2017 and 2020, ranges from 1,700km^2 to 2,700km^2 with a most likely area of 2,200km^2.

- **EP 136** – This block lies adjacent to EP 161 in the core of the Beetaloo Sub-basin. EP 136 is comprised of approximately 4,230 km^2 that spans north-south with the greatest extent approximately 165 km and as much as 25 km in width. The estimates of Tamboran's gross prospective gas and condensate resources relating to its 100% interest in EP 136 range from 11.2tcf to 37.8 tcf.

- **EP 143** - EP 143 is an irregular block that is comprised of approximately 2,090 km^2 that extends approximately 45 km west to east and 55 km north to south. Initial focus and capital spend regarding the Sweetpea Assets will be on EP 136. Tamboran's plans for EP 143 consist of maintenance of the permit for future assessment.

- **EP(A) 197** - EP(A) 197 adjoins a portion of the northern boundary of EP 143. The irregular rectangular block is approximately 790 km^2. Tamboran's plans for EP(A) 197 consist of completing acquisition of the licence and maintenance of the permit for future assessment.

Valuation

Our favoured valuation methodology is a bottom-up risked NAV, in which we have built a DCF valuation of the prospective resources being targeted (assuming they will be developed), and then risked them for geological and commercialisation risk. Given that Tamboran currently has no production it is not possible to compare Tamboran to peers on earnings or cash flow metrics. We have looked at Tamboran versus peers on resource multiples but we see these as of limited use given the vast differences between the value and risks surrounding resources for difference companies. We have also looked at it versus the most comparable transaction in the Beetaloo basin.

In our base case scenario, we use US$65/bbl Brent long-term flat, a US$1.37/AUD exchange rate and a 10% discount rate from 1/1/2022. The most important driver of the valuation is the realised gas price for Tamboran, which we estimate based on an Asian LNG price and net off the costs of liquefaction and transportation to estimate a wellhead price. Our long-term Asian LNG price forecast is A$12/mcf (US$8.8/mcf), which is based on 13.5% of Brent. Generally long-term LNG contracts are priced off a percentage of crude oil in US$/bbl and then put into US$/mcf (for example at US$100/bbl and using 10% of Brent would give an LNG price of US$10/mcf).

Our risked NAV is A$0.79/sh, which implies 132% upside from the current share price. On an unrisked basis we have a NAV of A$2.11/sh or >5x upside for the development of 3.5tcf net to Tamboran. At our NPV10 of ~A$0.4/mcf, Tamboran is pricing in a development of just 0.5tcf of resource. Falcon's farm-down to Origin last year, at the market's nadir in April, implied a value of ~A$335mm (150% higher than Tamboran's EV) for its gross contingent resource of 6tcf, which is only ~20% of Tamboran's net prospective resource.

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 (end Q2'21)						$63	$0.09			$63	$0.09
H2'21 spending						-$10	-$0.01			-$10	-$0.01
Capitalised G&A	@ 2x					-$16	-$0.02			-$16	-$0.02
Options proceeds						$5	$0.01			$5	$0.01
EP 136 - 1tcf		1037	100%	1037	0.45	$463	$0.69	50%	75%	$174	$0.26
EP 136 - incremental 1.75tcf		1750	100%	1750	0.36	$638	$0.95	50%	50%	$160	$0.24
EP 161		2750	25%	688	0.40	$272	$0.40	75%	75%	$153	$0.23
Total NAV						**$1,415**	**$2.11**			**$528**	**$0.79**

Source: H&P estimates

Net cash – We use the end-Q2'21 net cash position of A$63mm, which is the equivalent of A$0.09/sh or around 30% of the current market capitalisation.

H2'21 spending – We include an estimated A$10mm of spending for the remainder of 2021, which will primarily be spent on the Tanumbirini 2H & 3H Horizontal wells.

Options proceeds – We include 18mm options that have vested with an average exercise price of A$0.29/sh with total potential proceeds of A$5.2mm.

G&A – We include 2 years of G&A in our NAV, which we estimate at A$8mm per annum. This has a negative impact of A$0.02/sh.

EP 136 – We have looked at two scenarios on EP 136. The first has production reaching ~100mmcf/d and developing 1tcf of resource over time. The second scenario has production growing to ~250mmcf/d and developing 2.75tcf of resource.

EP 161 – For EP 161 we have assumed a scenario where production grows to ~250mmcf/d and this would recover ~2.75tcf over the life. We have been conservative in the scale of the development as there is the potential for EP 161 to produce at a higher rate than EP 161 given that Tamboran has full control over this asset and a deal with Jemena to take 500mmcf/d of capacity.

NAV sensitivities

We look at the risked NAV and the average NPV/mcf for Tamboran at various gas prices and discount rates relative to our base case.

Risked NAV (A$/sh) at various Australian gas prices (A$/mcf) and discount rates

		Australian gas price (A$/mcf)				
		$5.00	$7.00	$9.00	$12.00	$15.00
Discount rate	6%	0.03	0.82	1.61	2.81	3.98
	8%	-0.10	0.51	1.11	2.03	2.92
	10%	-0.17	0.31	0.78	1.51	2.20
	12%	-0.21	0.18	0.56	1.14	1.70
	14%	-0.23	0.09	0.40	0.88	1.34

Source: H&P estimates

NPV/mcf at various Australian gas prices (A$/mcf) and discount rates

		Australian gas price (A$/mcf)				
		$5.00	$7.00	$9.00	$12.00	$15.00
Discount rate	6%	-0.01	0.42	0.84	1.49	2.12
	8%	-0.07	0.25	0.57	1.06	1.54
	10%	-0.11	0.14	0.39	0.77	1.14
	12%	-0.13	0.07	0.27	0.58	0.87
	14%	-0.14	0.02	0.19	0.44	0.67

Source: H&P estimates

Recent transaction data

In April 2020 Falcon Oil and Gas announced a sell down of 7.5% of its stakes in the Beetaloo basin to its partner Origin in return for a carry of A$25mm, which implies a gross value of ~A$335mm. The gross resource associated with the deal is 6.6tcf of 2C resource, which implies a value of A$0.05/mcf.

Given that this deal was done during the peak of the COVID crisis at a time when global LNG prices were near record lows and oil and gas equites were also in the doldrums suggests that the valuation at the time was low and given that we are currently seeing record LNG prices and much more favourable equity market, we expect that if the deal was done today it would have been at a significantly higher price, especially given further positive news from the recent flow test of the Amungee NW well.

Tamboran has 31tcf of unrisked prospective resource so if it can convert just 20% of this to 2C it would have a similar 2C resource to the gross resource associated with the Falcon/Origin deal. At a similar value of A$335m (without adjusting higher for the more favourable current environment), this would still imply around 85% upside to Tamboran's current share price.

Peer group multiples

Tamboran's peer group reserves and resource data and multiples (A$mm)

Company	Market Cap	Net debt	EV	2P reserves (mmboe)	2C resources (mmboe)	EV/2P (A$/boe)	EV/2P+2C (A$/boe)
Armour Energy	49	43	92	25	12	3.7	2.5
Beach Energy	3,121	150	3,272	268	191	12.2	7.1
Cooper Energy	424	139	563	47	34	11.9	6.9
Central Petroleum	83	31	114	13	31	8.9	2.6
Carnarvon Petroleum	470	-99	371	0	120	n/a	3.1
Empire Energy Group	222	-32	189	6	0	n.m.	n.m.
Senex Energy	666	150	816	125	0	6.5	6.5
Falcon Oil & Gas Ltd.	155	-13	142	0	243	n/a	0.6
Strike Energy	587	-69	518	0	166	n/a	3.1
Tamboran Resources	**222**	**-63**	**159**	**0**	**0**	**n/a**	**n/a**

Source: H&P estimates, Company data, S&P Cap IQ

Given that Tamboran currently has no production it is not possible to compare Tamboran to peers on earnings or cash flow metrics. We have looked at Tamboran versus peers on resource multiples but we see these as of limited use given the vast differences between the value and risks surrounding resources for difference companies.

The peer group that we are looking at are the mid-market Australian listed E&P companies and we have also added in Falcon Oil and Gas, which we believe is the closest comparable from an asset perspective. Although the resource multiples are of limited use, one thing that it demonstrates is the value that the market could put on Tamboran if it is successful in proving up contigent resources and converting these to reserves. The average EV/2P is A$8.7/boe and EV/2P and 2C is A$4.1/boe – using the 2C multiple, Tamboran would need to book ~250bcf (40mmboe) in contingent resource to justify its current EV of ~A$150mm.

Tamboran's peer group total shareholder returns (USD terms)

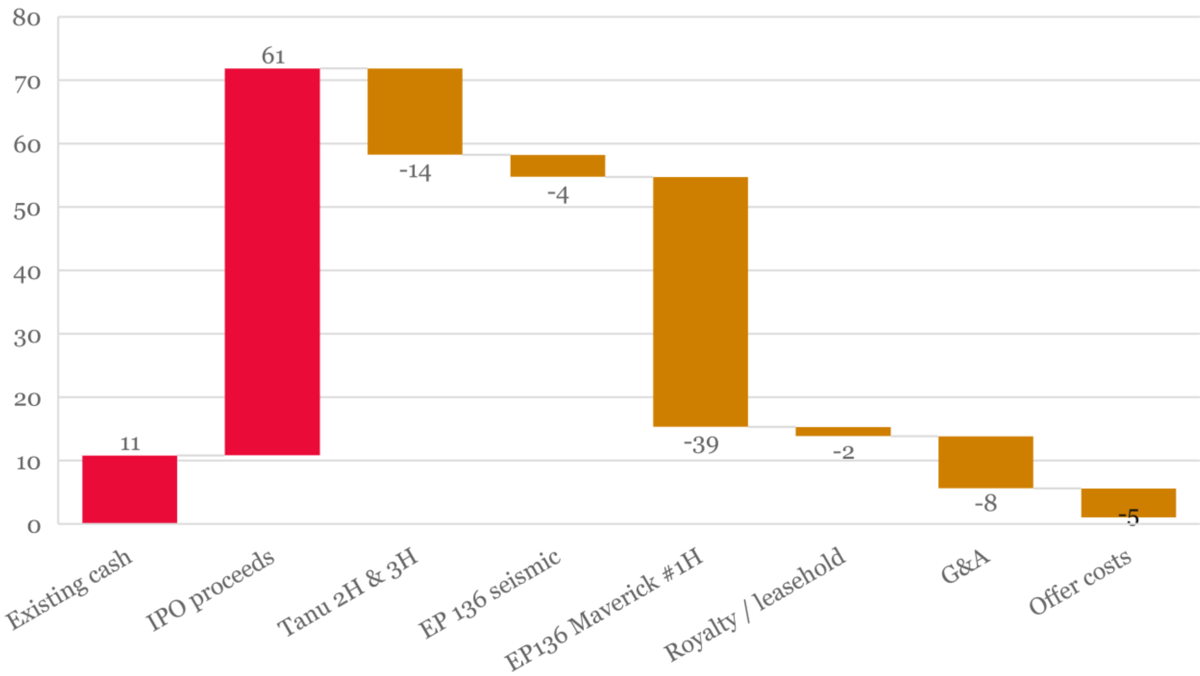
Company	YTD	1 month	3 month	1 year	2 year	5 year
Armour Energy	-53%	-25%	-8%	20%	-52%	-67%
Beach Energy	-28%	27%	7%	1%	-41%	114%
Cooper Energy	-38%	16%	-4%	-26%	-52%	-23%
Central Petroleum	-18%	13%	-6%	-3%	-32%	1%
Carnarvon Petroleum	-7%	21%	15%	38%	-18%	168%
Empire Energy Group	-3%	26%	9%	13%	102%	167%
Senex Energy	39%	13%	2%	44%	45%	76%
Falcon Oil & Gas Ltd.	-14%	50%	28%	8%	-31%	82%
Strike Energy	-5%	8%	-13%	11%	26%	175%
Tamboran Resources	n/a	46%	n/a	n/a	n/a	n/a
Average (ex-Tamboran)	**-14%**	**16%**	**3%**	**12%**	**-6%**	**77%**

Source: H&P estimates, S&P Cap IQ

Balance Sheet and Funding

Following the IPO and fund raising, Tamboran has 653mm basic shares in issue. It has a further 18mm options that have vested with an average exercise price of A$0.29/sh with total potential proceeds of A$5.2mm. We include these in our fully diluted share count of 671mm shares. There are a further 16mm "Milestone Options" that are based on the share price reaching certain levels between A$1.00/sh and A$2.50/sh and would have an exercise price of A$0.40/sh. Given that these options are a large way out of the money, we do not include them in our diluted share count.

Planned use of cash



Source: Company Data

Tamboran's latest reported cash position was A$63mm at the end of Q2'21 and the company has no debt. The company had ~A$70mm following the A$61mm raise through its IPO at a share price of A$0.40/sh. Since then, it has spent ~A$5mm on exploration and ~A$1mm on G&A. The main area of spending this year is on the Tanumbirini 2H and 3H wells, which are estimated to have a net cost of A$14mm to Tamboran.

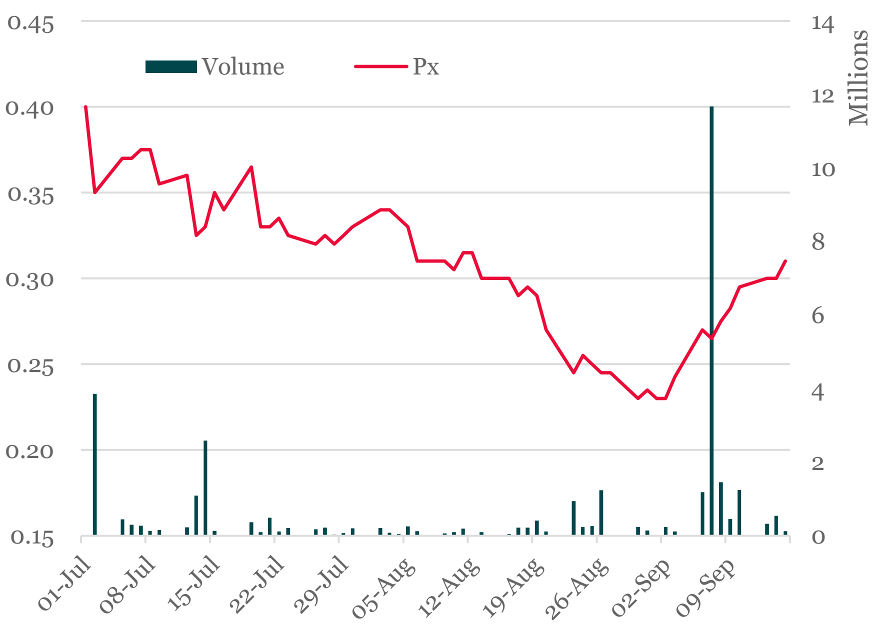
Top Shareholders

Holder	Shares (mm)	%
Longview Petroleum, LLC	143	21.9
The Baupost Group, LLC	130	19.9
Lion Point Capital	70	10.7
Regal Funds Management Pty Limited	39	5.94
Venture Holdings	34	5.23
Geotech Investments Pty Ltd.	33	5.12
Elliott, Patrick (Non-Exec)	23	3.57
Pictet Asset Management Limited	8.7	1.33
Raycap Asset Holdings Pty Ltd	6.3	0.96
Tidey, Gillian Leslie	5.2	0.80
Falvey, David Alan	5.2	0.80
Riddle, Joel (CEO, MD & Director)	3.8	0.58
Mst Financial Services Pty Ltd	3.4	0.52
Siegel, David N. (Non-Exec)	2.8	0.43
Dyer, Eric (Chief Financial Officer)	2.5	0.39
Barrett, Fredrick J. (Non-Exec)	2.2	0.34
Stoneburner, Richard (Chairman)	2.1	0.32
Chandra, Daniel (Non-Exec)	1.9	0.29
Morbey, Joanna (Company Secretary)	1.0	0.16
Diamant, Ann (Non-Exec)	0.4	0.06

Source: S&P Cap IQ

Trading liquidity

55% of shares are currently locked up following the IPO for a period of up to 24 months. Once the lock-ups expire there will be the positive of additional trading liquidity but also the risk of existing shareholders selling down into the market. Liquidity is improving, but post IPO there was a very low turnover in the stock. The stock lost a significant amount of value since the IPO in July to early September but on very limited volume. Excluding one large institutional trade of 10mm shares in early September, since the IPO up until mid-September only ~3% of shares outstanding have traded since the IPO. The lack of liquidity could also see the shares squeeze higher on positive news flow.



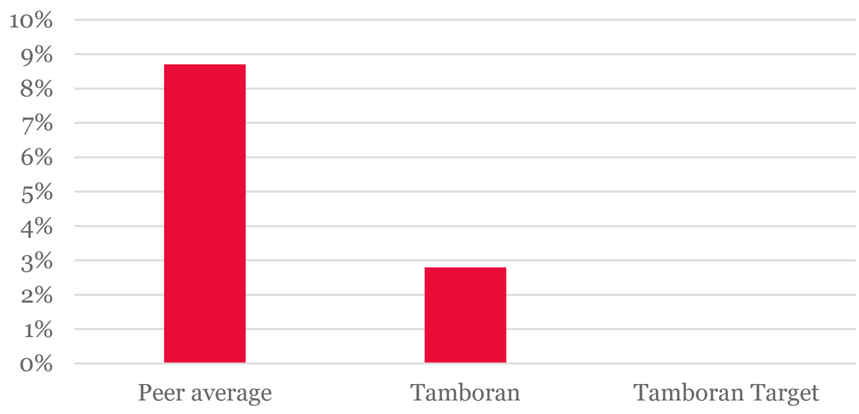
Source: Bloomberg

HANNAM&PARTNERS

ESG policies

ESG is an increasingly important issue for investors in the oil and gas industry. 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.

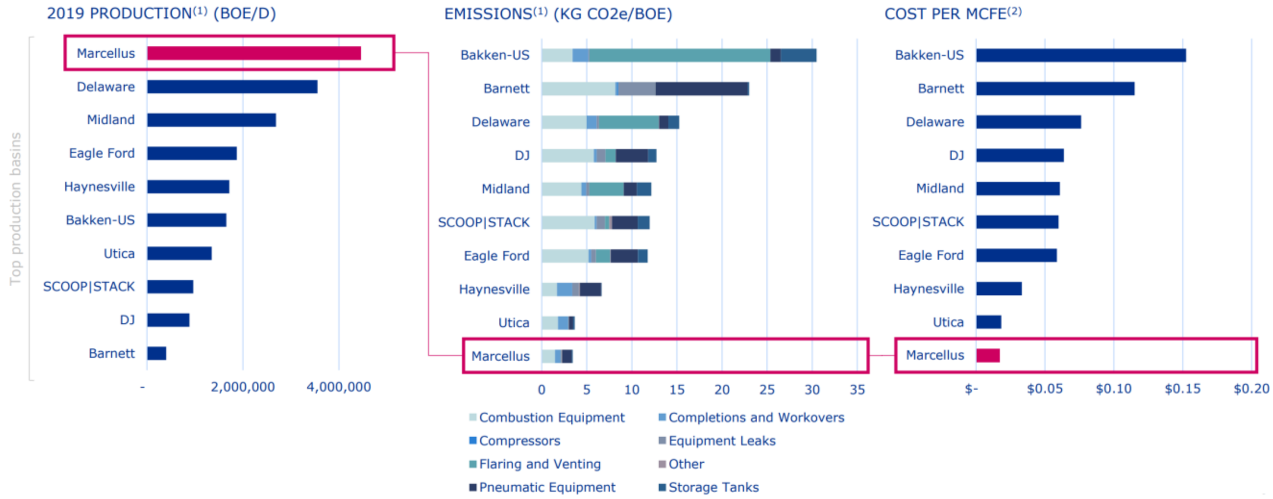
Approximate CO2 contained in reservoir



Source: Tamboran; Peer average includes Barossa, Gorgon, Browse, Ichthys, Prelude, Wheatstone, Bayu Undan, Janz and Scarborough

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. In a future where a carbon tax may be applicable having less CO2 in the gas stream may provide a lower offset or displacement cost.

Marcellus' Leading Emissions Intensity Translates to Lower "Cost of Carbon"



Source: EQT; Assumes $30 per ton CO2e and a 6:1 mcfe to boe conversion factor

The use of fracing in the United States led to an abundance of affordable natural gas and the decline of coal as the primary fuel for electricity. Natural gas provided 38% of U.S. electricity production in 2019, up 2.4x since 2000. The Marcellus shale (a key analogue of the Beetaloo) has also provided the largest contribution to the U.S. gas supply while coal usage by the power sector has declined by 50%. Marcellus natural gas is the clear low-cost, low-emitting energy source.

Also, producers looking to supply the likes of Japan's remaining LNG demand in the years ahead will likely have to demonstrate strong emissions credentials (such as by supplying carbon-neutral LNG) on top of higher flexibility and lower costs. This could put some emission-intensive projects in Australia (Ichthys, Barossa, Prelude) on the back foot, while volumes out of US and Russia could face scrutiny over upstream flaring and venting. This plays into the hands of Tamboran's strategy of producing carbon neutral LNG on a Scope 1 and 2 basis.

Sustainability

Tamboran's Six Sustainability Pillars are:

1. Health and Safety: Putting health and safety first

2. Climate Change: Playing a role in the transition to a lower carbon economy

3. Environment: Applying leading North American drilling technologies to promote efficiency and minimise environmental impacts

4. People: Attracting, developing and retaining a diverse, inclusive and competent workforce

5. Community: Partnering with its local and host communities to share value

6. Economic Sustainability: Generating economic growth and value for its investors, employees, customers and communities

The Sustainability Committee will oversee the annual production of a Sustainability Report. Tamboran plans to complete the first Sustainability Report in relation to the 2021/22 financial year. Tamboran intends to implement the following sustainability reporting:

- Adoption of the materiality identification framework set by the Sustainable Accounting Standards Board (SASB).

- Reporting climate change using the framework approved by the Taskforce on Climate Related Financial Disclosures (TCFD).

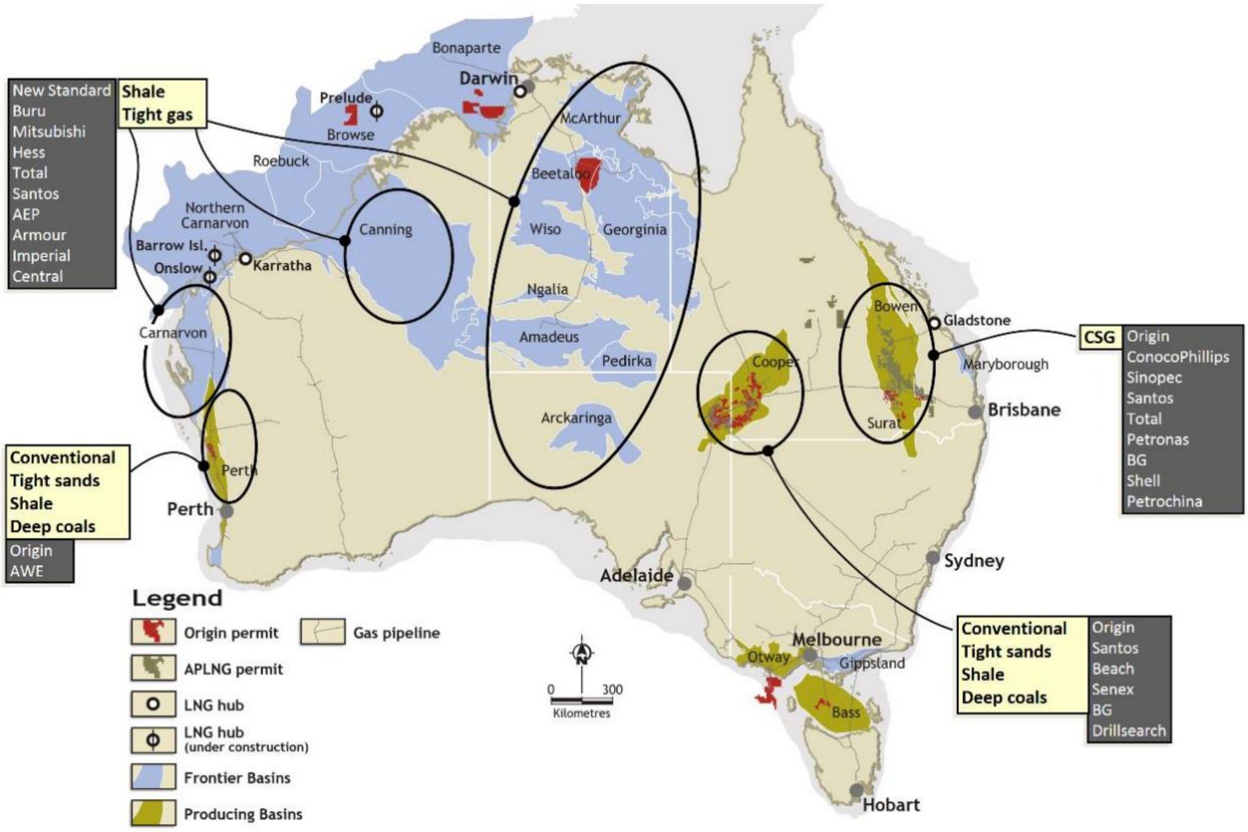
- Integration of relevant reporting metrics for the Global Reporting Initiative (GRI).

- Reporting relevant metrics and targets to demonstrate our sustainable approach to operations and becoming a net zero carbon producer.

- Reporting the impact of our operations on relevant UN Sustainable Development Goals.

Australian shale potential

Unconventional shale gas exploration in Australia



Source: Close et al. 2016 AGES, "Unconventional gas potential in Proterozoic source rocks: Exploring the Beetaloo Sub-basin

We believe that the Beetaloo is well positioned to be successful given the geology and other commercial considerations. In the Beetaloo, with source rocks that are much thicker than comparable US shale plays, there is potential for world-class resources, and it is considered by many to be the most prospective shale play globally. The Beetaloo Basin represents one of the few remaining virtually unexplored, onshore sedimentary basins in the world. The fact that this basin is in a developed market country with a stable political, legal and regulatory system makes this basin all the more significant. The Government of the Northern Territory and the Government of Australia both have a positive attitude towards oil and gas exploration and development and a very favourable fiscal regime.

Although unconventional oil and gas plays exist in many regions around the world, 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. This has been reflected in Tamboran homing in on the Northern Territory in Australia and relinquishing its assets in South Australia, Western Australia, Turkey, Myanmar, the United Kingdom, Northern Ireland and Botswana in 2015.

Key successful shale play considerations

Geology: The quality of the rocks is important for determining the economics of a play. Most prospective shales tend to have TOCs > 2%, Vitrinite Reflectance factors (%Ro) between 0.55% & 1.4% and brittle rock (improves fracing effectiveness). In addition, thick (>50ft) and structurally simple (low tectonic stresses and fewer faults) shales are preferable. (See page 21 for more detail)

Economic Incentives: Both producers and landowners need to be rewarded for hydrocarbon development. E&P companies require a stable fiscal regime (tax and royalty/PSCs) with low political risk, which offers the opportunity to generate a fair return, whilst landowners need to be adequately compensated for the "inconvenience" of having roads, well sites, drilling rigs, frac spreads, etc. on their property. Natural gas from shale is far less land intensive than mining or even CSG. In the Beetaloo, Tamboran benefits from attractive federal fiscal terms as well as further incentives in place. Also, the remote location means that there is little worry about disruption given low population density and there is a NT government regulated compensation structure in place for the pastoralists and traditional owners to receive compensation. The Northern Territory Government had previously imposed a moratorium on the operations in the Beetaloo Sub-basin, which ended in 2018 following a scientific inquiry and certain recommendations.

Service Availability and Efficiencies: It is nice to have a favourable subsurface environment and adequate economic incentive, but oil and gas resources neither produce themselves nor take themselves to market. Service (and midstream) infrastructure is imperative, and so it is no surprise that the shale boom began in North America, where there is an abundance of service capacity. In Australia the service industry is already established, but more capacity will be required, including fit for purpose rigs and additional pressure pumping availability, for which there is currently plenty of global capacity. Tamboran's team has many decades of sourcing oil services and experience drilling wells efficiently and bringing costs down: The cost of drilling an onshore exploration well is currently more than two and a half times that in the US.

Market Access & Pricing: Without access to demand centres, markets can very quickly become saturated with oil, gas and natural gas liquids (NGLs), adversely affecting pricing. This happened in the US with the solution being a boom in LNG export facilities to access global gas pricing. Australia benefits from having ample access to LNG markets through its sizeable export capacity, with easy and cheap access into the Asian market. This is a big competitive advantage versus US LNG exports whose transportation costs to Asia are multiple times higher.

Infrastructure: The growth of shale in the US overwhelmed the market causing large variations in oil and gas prices within North America and creating market dislocations. Therefore, it is important to have a plan to put infrastructure in place. Tamboran's management clearly has plenty of commercialisation experience from the US and as a result has pre-empted these issues by putting agreements in place to ensure the necessary infrastructure will be there if and when it moves to development.

Access to Capital: Shale oil and gas field development is capital intensive, given the continuous drilling requirements and can lead to years of negative free cash flow. Combined with a substantial infrastructure requirement, exploitation cannot be done cheaply. Tamboran's recent listing on the Australian market provides it access to capital and being partnered with a strong players such as Santos and Jemena is also very important. There have also been ~US$2bn of JV deals done for Australian unconventional oil and gas assets over the last decade, demonstrating a relatively liquid asset market.

Regulatory & Environmental Acceptance: In considering the impact of shale oil and gas production and fracing on the environment, it is worth noting that the process has been carried out safely for decades. Issues that need to be understood and managed include ground water contamination, hassle factor, chemical handling, waste disposal, air quality and water use. This is an area where it is crucial to have an experienced management team that has dealt with all these issues in North America.

Government policy

The Northern Territory's Geological Survey estimates the Beetaloo basin could hold more 190tcf of gas. The federal government has previously claimed that if even 10% of that estimated figure was recovered, it would be enough to supply Australia's domestic gas demand for more than 10 years.

The Australian government launched A$50mm in new grants to encourage further exploration of the Beetaloo basin, through the Beetaloo Cooperative Drilling Programme. It is expected to enable the drilling of 10 additional exploration wells in the Beetaloo by 2022, as well as bringing forward at least A$150mm of private investment. The programme forms part of the federal government's wider "Beetaloo Strategic Basin Plan" to generate significant development, creating up to 6,000 jobs over the next 20 years and helping Australia remain a world leader in gas.

The government also unveiled plans to invest A$217mm in the new Northern Territory Gas Industry Roads Upgrades corridor, which it hopes will also help unlock the Beetaloo basin's potential.

The government of the Northern Territory had imposed a moratorium on fracing between 2016 and 2018, eventually allowing it to restart under a new Code of Practice that covers surface activities, well operations, water management and methane emissions. In the finalised Code of Practice, the government is committed to implementing all 135 recommendations published by the Independent Scientific Inquiry into Hydraulic Fracturing, notably including provisions regarding wastewater treatment and disposal, methane emissions and surface activities.

Understanding the geology

Total Organic Content (TOC) - An indication of the rock's potential to generate large amounts of hydrocarbons. It is agreed among the industry that a TOC>2% (by weight) is required for a rock to be considered as a source rock therefore suitable for shale gas/shale oil production.

Vitrinite Reflectance (%R_o) – It measures the thermal maturity of the organic matter (kerogen) within the rock. Together with the type of kerogen, it indicates if the generated hydrocarbons are either oil (0.55 – 1.15% Ro), wet gas (1.15-1.4% Ro) or dry gas (Ro>1.4%). Over-mature rocks (Ro>2.1%) have destroyed hydrocarbon potential.

Mineralogy – Brittle rock (high silica) with adequate porosity (4-12%) and permeability (>100 nanoDarcies) helps enable frac effectiveness. Low clay content and natural fracturing are also helpful. Marine-deposited shales tend to have better mineralogical properties than lake deposited (lacustrine) ones.

Thickness – A thick formation is better as fracing is more effective if the entire fracture lies within the shale formation. Thick rocks potentially hold more hydrocarbons. A formation thicker than 50ft is desirable.

Depth – Impacts the economics of any unconventional play. Drilling depth adds cost but can also add necessary pressure. The US EIA states prospective depths should typically be within 3,300 and 16,500ft for the organic matter to be subject to adequate thermal maturity.

Pressure Gradient – Over-pressured rocks provide increased level of natural drive.

Structural Simplicity – Numerous faults and high tectonic stress have been factors affecting the economics and performance of unconventional wells. High degree of faulting makes drilling a horizontal well more difficult. High breakdown pressures and fluid leak-off can result in poor stimulation.

McArthur Basin

Greater McArthur Basin region in Northern Territory is located about 500 kilometres south-east of Darwin. It is highly prospective for unconventional gas and is recognised as a close analogue to some of the most productive unconventional gas basins in North America (i.e. Appalachian Basin). According to the Australian government's latest assessments, the Northern Territory is estimated to hold total unproven prospective shale gas resources of 244tcf.

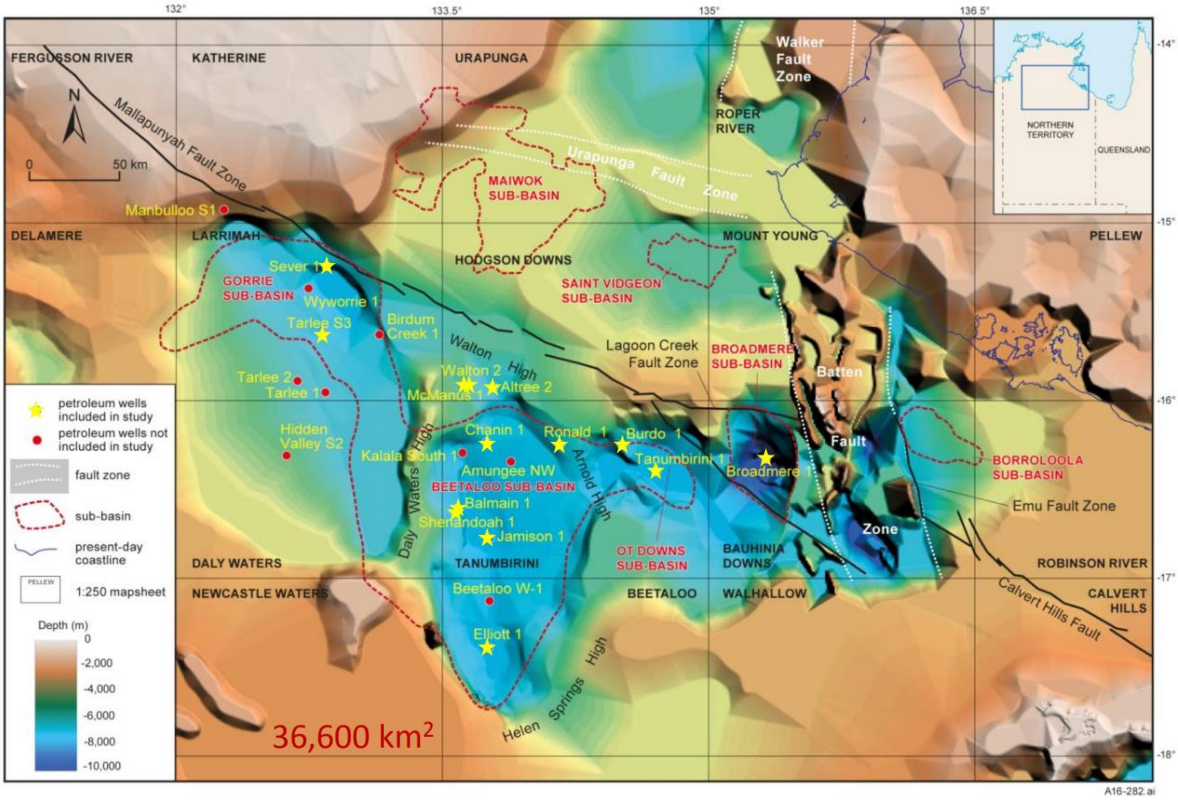
The McArthur Basin underlies much of the northeastern NT and contains a succession of sedimentary and minor volcanic rocks that are up to 15 km deep. Some 70% of the estimated resources are found in the Beetaloo Sub-basin. Multiple structural sub-basins have been identified in the greater McArthur Basin and serve as local depocenters for sedimentary accumulation:

1. O.T. Downs Sub-Basin
- Tanumbirini 1 demonstrates greatest shale thickness and potential of any well drilled to date, base of Mid Velkerri penetrated at ~3,600m and penetrated 270m of prospective shales.

2. Beetaloo Sub-Basin
- Shenandoah 1a exhibits very poor shale development but produces minor flow on fracture treatment.
- Amungee NW-1 well followed up immediately with Hz well with 12 frac stages attempted over 700m producing ~1.2 mmcf/d test rate despite incomplete clean up, casing collapse and failure to drill plugs.

3. Gorrie Sub-Basin
- There is an intrusion called the Derim Derim Dolerite sill, which is a structural uplift of the basement. Therefore the western flank is much shallower than the eastern side and this uplift has compartmentalised the shale, so it is not as homogenous as the depocenter.

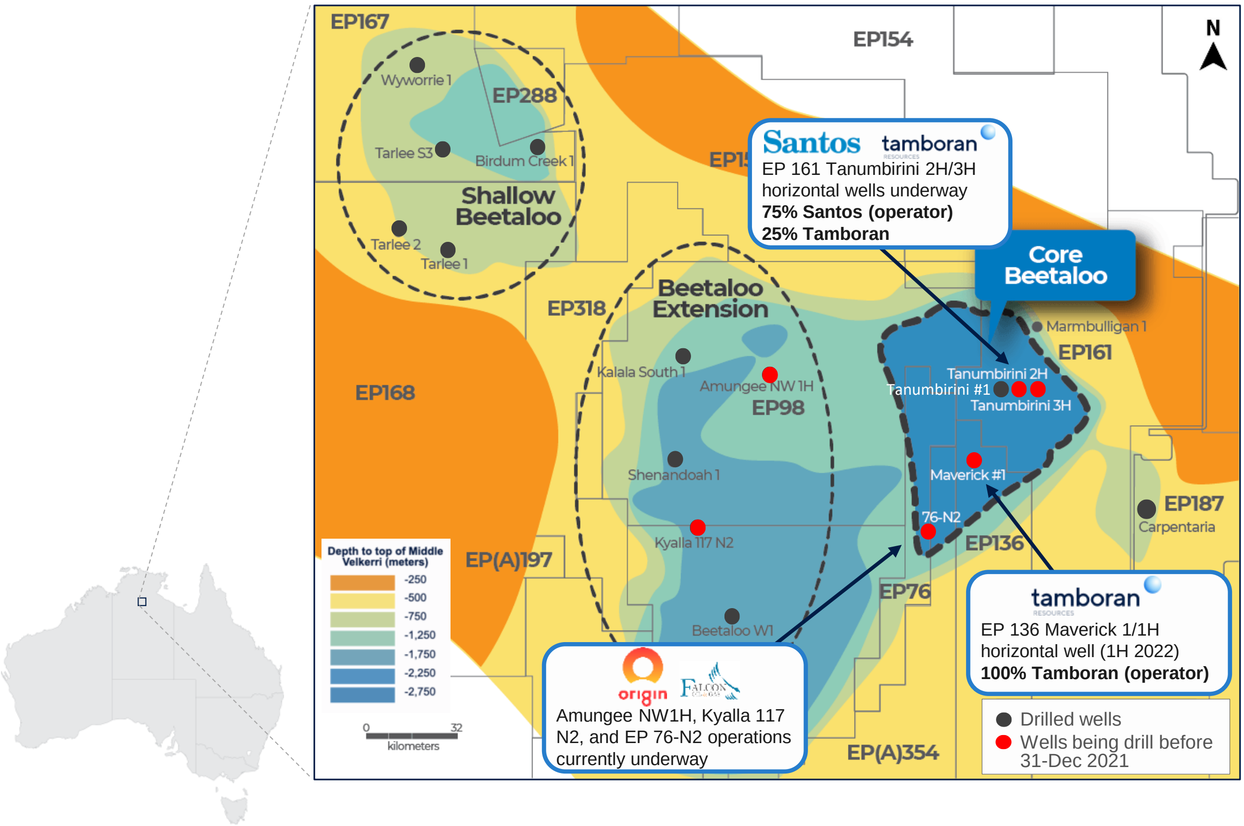
Geography of the McArthur Basin



Source: Image from: Revie, D. J., 2016b, after: Munson 2016, Sedimentary characterization of the Wilton package, greater McArthur Basin, Northern Territory. Northern Territory Geological Survey, Record 2016-003.

Beetaloo Sub-basin

Beetaloo Basin Regional Map (Mid-Velkerri Shale)



Source: Tamboran Presentation

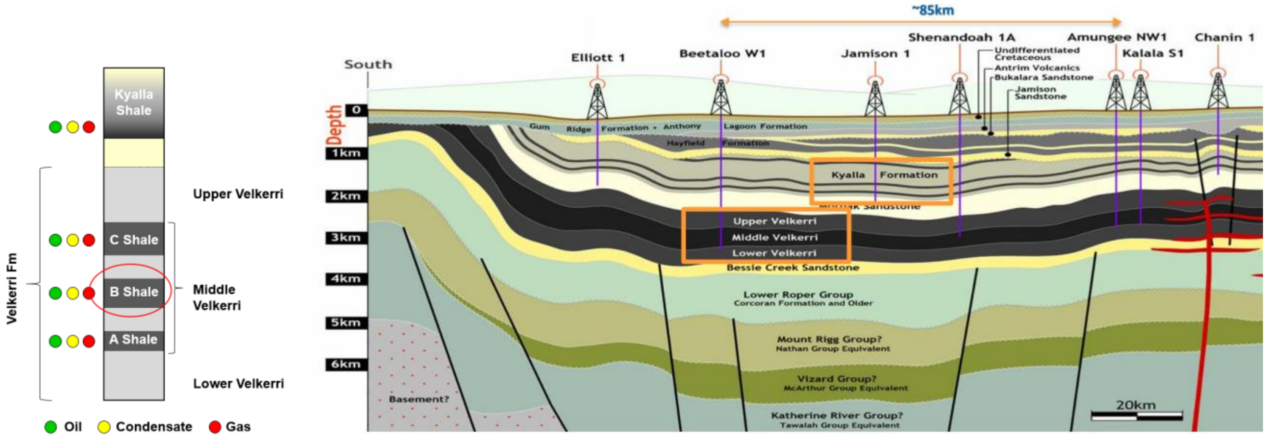
The Beetaloo Sub-basin covers an area of approximately 30,000 sq km in the Stuart Plateau region and is comprised of the McArthur Basin's youngest rock unit, the Roper Group, containing the Velkerri and Kyalla formations. The Beetaloo Sub-basin is one of the largest depocenters in the region and typically lies below the surface, up to a depth of approximately 10,000m. The primary targets are the Kyalla and Velkerri formations that are part of the Mesoproterozoic Roper Group. The Roper Group reaches to a depth of 5,000m in the centre of the Beetaloo Basin. The permit areas are composed of Pre-Cambrian rock formations located at depth and beneath the younger formations.

Located in the southern part of the Greater McArthur Basin, the Beetaloo Sub-basin is structurally subdivided into three geographical areas and two major structural highs. The north-south trending, structurally complex Daly Waters Arch (west) and the structurally benign Arnold Arch (east) divide the area into three major depocenters.

The Beetaloo's prospectivity has been confirmed through extensive exploration drilling by Santos/Tamboran, Origin and Pangaea. Reservoir gas from the Beetaloo Basin appears to contain very low CO_2 (~3%) and has no major impurities (such as sulphur and inerts). To date, the majority of expenditure in the Beetaloo has been on vertical wells, seismic and core. The basin is sparsely populated and its proximity to infrastructure, including the Amadeus Gas Pipeline (AGP) [North/South], McArthur River Pipeline [East / West] and Northern Gas Pipeline (NGP) [East / West], makes it favourable for supplying gas to the East Coast gas market within a decade.

The other companies that are involved in exploration of the Beetaloo are Santos which is partnered with Tamboran; Santos operates EPs 161. Origin Energy as operator and Falcon, which are partnered on blocks EP 117, EP 76 and EP 98. Origin increased its stake to 77.5% from 70% with Origin increasing its carry by A$25mm to A$59mm. Empire Energy owns EP 180-187 and added EPs 167, 168, 169, 198 and 305 through the acquisition of Pangaea announced in April 2021.

Target formations



Source: Tamboran Presentation and Falcon Oil & Gas Presentation

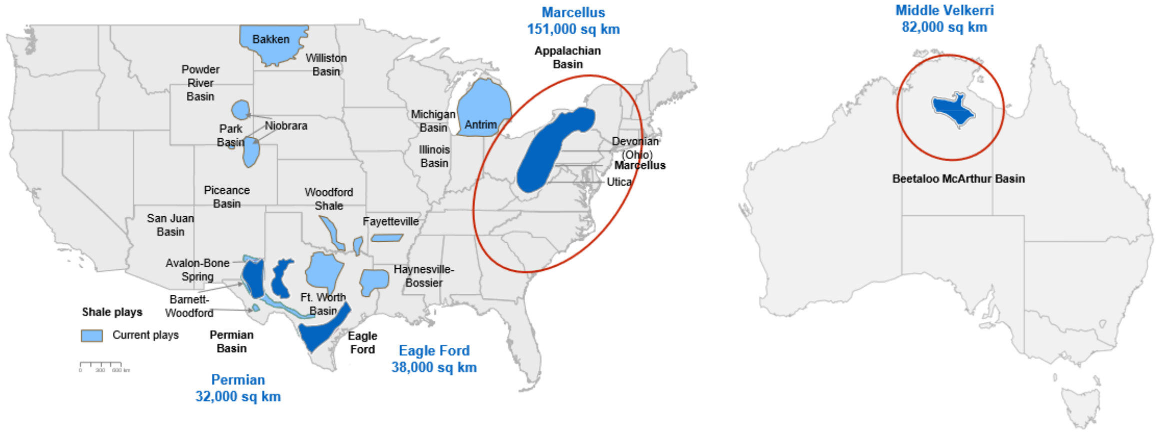
The Middle Velkerri and Kyalla shales are the primary targets for oil, condensate and gas which has been confirmed by the federal government's draft report on the Beetaloo. The Velkerri shale was estimated to have 500tcf of gas in-place across the Beetaloo according to the NT Government in 2018. The first booked contingent resource was by Origin in 2016 for the Middle Velkerri B shale (6.6tcf dry gas).

The core of the basin is seen as homogenous as the thickness stays constant and there is no significant faulting. Also the pressure regime has been shown to be constant through the basin and deeper zones in shale basins have consistently shown increased prospectivity and production.

The Middle Velkerri Formation is a quartz rich organic shale with exceptional fracability. Unlike many US shales organic carbon is positively associated with frac friendly minerals including quartz (organics are most often associated with clay levels that preclude effective fracture stimulation). The organic carbon preserved within the Middle Velkerri was of exceptionally high capacity to generate hydrocarbons partly because of the very low oxygen levels in the atmosphere during deposition. The result is a shale that is highly fracable with excellent levels of gas filled porosity. Dry gas production is far less demanding in terms of permeability when compared to US shales that require liquids to be economic.

One risk that has been suggested is that the stress regime in Australian shale formations may be different to that found in the large American shale plays. The occurrence of a reverse stress regime could substantially reduce the effectiveness of fracing. There is a lot of compression (NE to SW pressure) which created the core of the Beetaloo. However, Tamboran sees this as a low risk and will look to mitigate this in any case by drilling perpendicular to the stress direction. The Tanumbirini 2H and 3H wells will be drilled at different angles to the stress effects to see if there is any impact on performance.

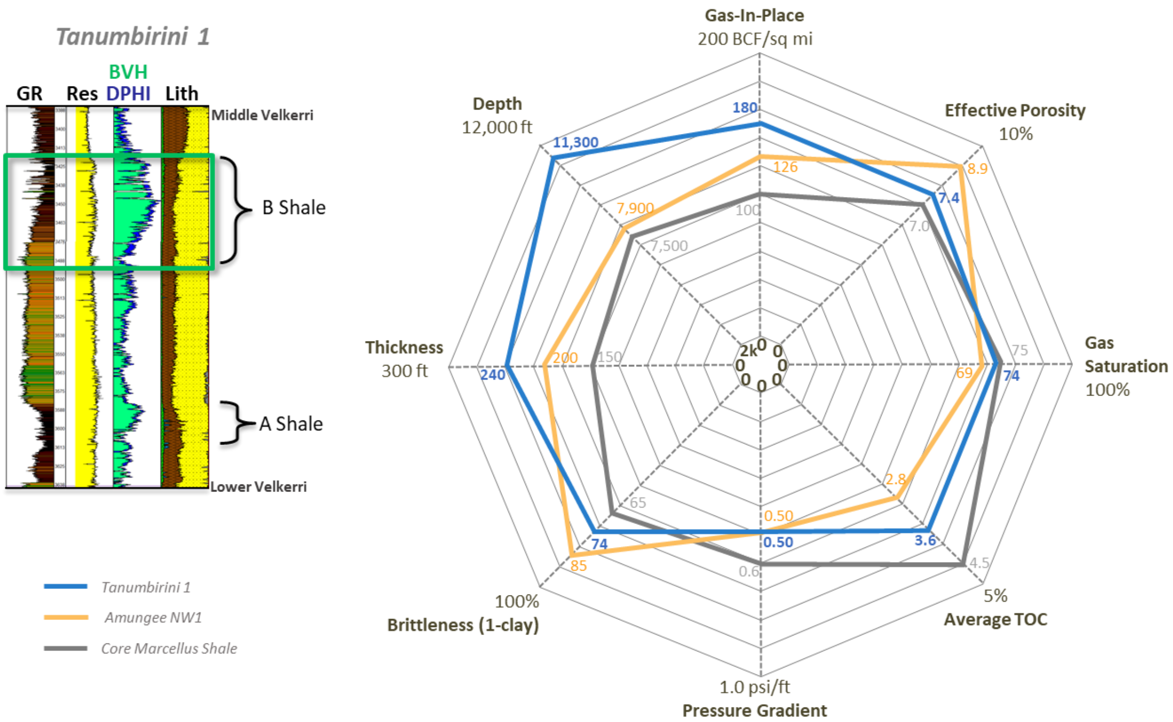
Similarities between the Beetaloo Sub-basin and Marcellus Shale



Source: Tamboran Presentation

The Marcellus Shale has been the most prolific gas shale in the United States and is the single largest contributor to natural gas replacing coal for power generation. Across the Beetaloo, the major participants Santos/Tamboran, Origin/Falcon and Pangaea Resources have all found common data in their Beetaloo drilling and analysis, that mirrors the Marcellus Shale in the USA. This type of development is now well understood and largely de-risked from the USA learnings.

Comparison of geologic attributes: Marcellus Shale vs. Velkerri "B" Shale



Source: NTGS, EIA, AGES, Core Labs Data Consortium

There is a clear similarity based on geologic attributes between regions. The Beetaloo's Middle Velkerri B shale reservoir properties are consistent across all neighbouring operators and analogous to the Marcellus. Marcellus Shale in Pennsylvania has one of the highest deliverability shales in the World with Gas in Place (GIP) of up to 150 bcf/section. Beetaloo's Middle Velkerri 'B' and 'C' shale GIPs contain 160- 200 bcf/section based on recent 3rd party (NCS) estimates integrating probabilistic GIP methods. Reservoir thickness and permeabilities within the Middle Velkerri 'B' and 'C' Shales also exceed Marcellus Shale.

Santos and Origin's drilling results and reservoir properties are consistent with the Marcellus too. Given the significant consistency across all of the major operators in the basin, the evidence implies:

- Uniform regional lithology
- Presence of moderate overpressure (0.51-0.59 psi/foot)
- Attractive permeability and porosity
- Favourable mineralogical properties to allow fracture stimulation
- High gas in-place concentration
- Consistently low CO_2 (<2%) across all wells

The data compiled to date from Tamboran's Tanumbirini #1 well and vertical frac indicates that horizontal wells in the Beetaloo Basin's Middle Velkerri Shale Formation have potential to be on par or better than wells in the core Marcellus Shale, currently the most prolific unconventional gas shale play in North America.

Exploration History

Historical exploration in the basin prior to 2014 was focused on conventional targets. These efforts found a wide distribution of gas shows and tests throughout the basin with most interest focused on the Beetaloo Sub-basin. More than 30 exploratory wells have been drilled in the Greater McArthur Basin, with most of these wells located in the Beetaloo Sub-basin. Close to half of these exploratory wells have been drilled over the past 10 years.

While there has been no commercial gas production to date in the Beetaloo Sub-basin, significant exploration activity is underway. Nineteen wells are located within the Beetaloo Sub-basin outline as defined by the Northern Territory Geological Survey. Five wells are located within the western sub-basin and 14 are located within the eastern sub-basin.

A rough timeline of the exploration activities that have taken place in the basin are as follows:

1964: Petroleum exploration first began in the larger McArthur Basin adjacent to the eastern edge of the Beetaloo Basin with an airborne magnetometer survey run by Barkley Oil.

1966: Barkley Oil conducted an aeromagnetic survey run.

1979: Kennecott Minerals had a gas blowout in one of its shallow mineral wells. This blowout led to increased interest by oil companies, academics, and government agencies such as the Bureau of Mineral Resources (BMR).

1984: Amoco drilled the first petroleum exploration well in the McArthur Basin (Broadmere #1) to the east of the Beetaloo Basin. The BMR also drilled several stratigraphic core-holes in the area, the majority within the McArthur Basin east and north of the Beetaloo Basin. Pacific Oil & Gas began acquiring 2D seismic over the McArthur and Beetaloo Basins. From 1984 to 1988 approximately 2,700-line kilometres of 2D seismic was acquired, and approximately 10 wells were drilled all within the McArthur Basin.

1985: Several Urapunga stratigraphic holes were drilled near the northern border of the McArthur Basin, and were reported to have encountered live oil in shale intervals.

1988: Between 1988 and 1993, Pacific acquired several 2D seismic lines within the Beetaloo Basin and drilled a total of eleven wells. A few of the wells had good oil and gas shows and some recovered gas and oil on DST. Pacific intended to complete the well in the Upper Kyalla, however, that completion was never undertaken.

2004: Sweetpea acquired EP 79, 98 and 99 and commenced an intensive exploration program in the Beetaloo Basin.

2006: Approximately 700km of new 2D seismic was acquired and integrated with the older seismic.

2007: In August, the Shenandoah #1 Well was spudded and drilled to a depth of approximately 1,550 meters, bottoming in the Mid Kyalla Sandstone. The well was drilled as a twin to the Balmain #1 Well which was extensively cored and tested. High gas readings were recorded over the Upper Kyalla interval.

2009: In August, Falcon Oil & Gas Ltd re-entered the original Shenandoah #1 Well and deepened it to 2,714 meters KB. Two cores were taken in the well, one over the Lower Kyalla gas-rich shale interval and the second over the organic rich Middle Velkerri A and B zones. Detailed core analyses were done on these two cores, which provided important new information on the shale resource potential in these deposits.

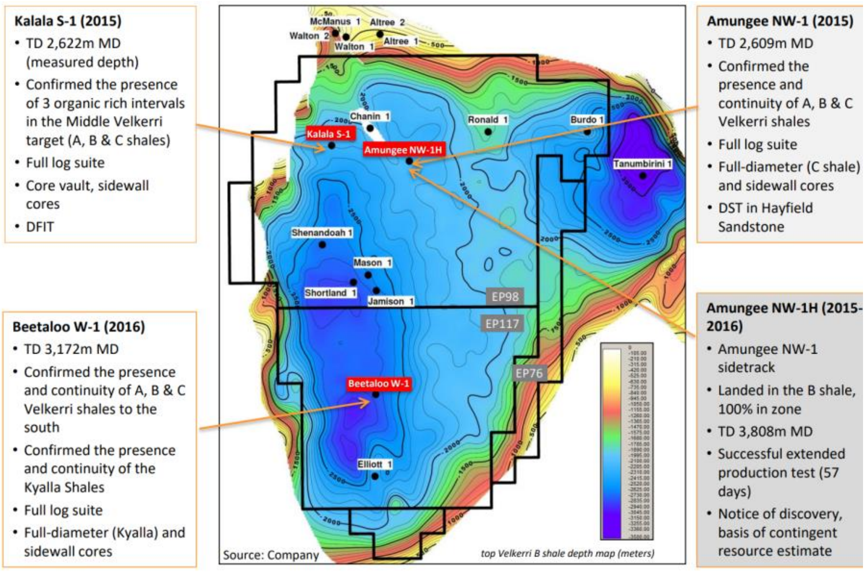
2011: Falcon Oil deepens Shenandoah 1 and fracture stimulates interbedded shale and sandstone resulting in gas flow with a small amount of condensate.

2013: Pangaea Resources drills Tarlee S3 which penetrates 111 m of shale bisected by a volcanic sill.

2014: Santos/Tamboran drill basin centred Tanumbirini 1 to 3,938m that penetrates 430m of Middle Velkerri estimated to hold over 500 bcf/section of dry gas across three shales.

2015: Pangaea Resources drills four vertical wells with two receiving small fracture stimulations delivering small amounts of gas to surface.

Falcon/Origin drilling programme



Source: Tamboran

2015-2016: Origin/Falcon/Sasol JV drills three wells including Kalala S1, Beetaloo W1 and Amungee NW1.

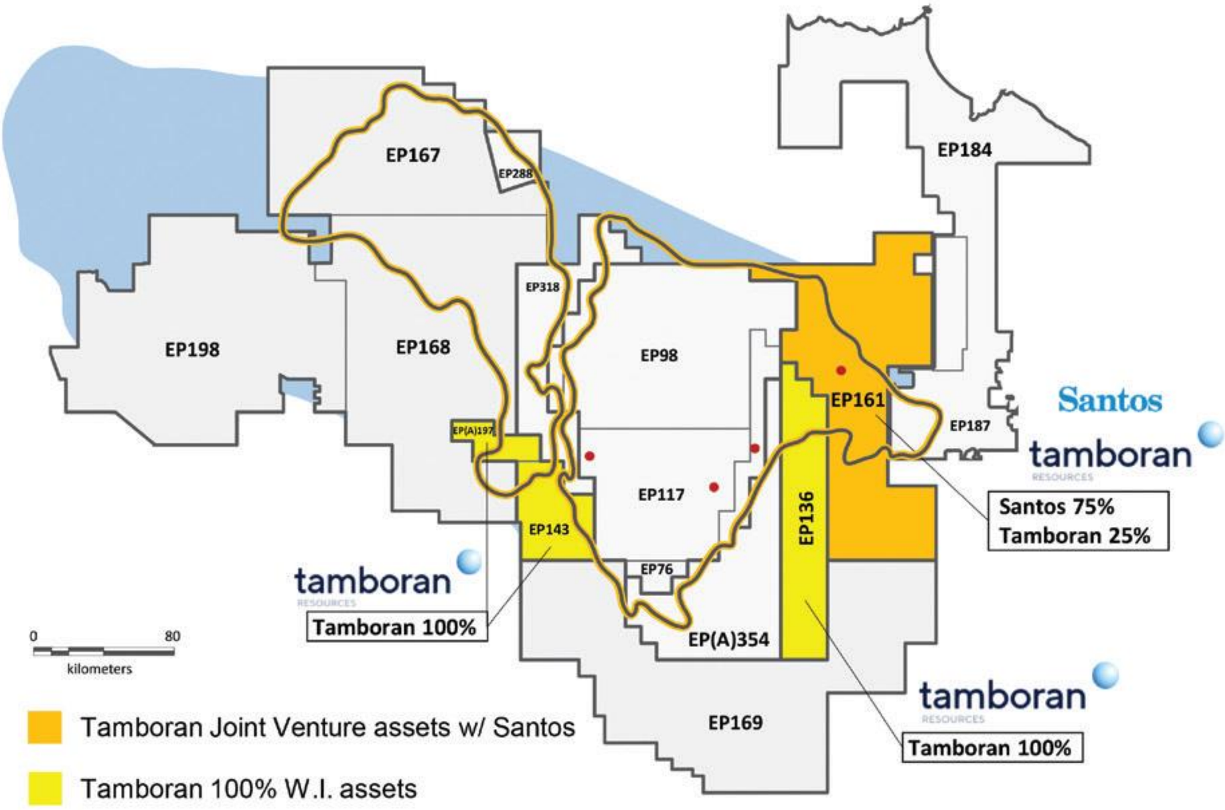
- The JV immediately added a Middle Velkerri 'B' shale focused horizontal leg to Amungee NW1.
- Fracture stimulation faced challenges in placing some stages and the drilling of plugs thereafter.
- Average rates of 1.1 mmcf/d over the period of the flow test.

2016-2018: NT Frac Moratorium prohibits activity.

2019: Tanumbirini 1 vertical well fracture stimulated.

2021: Commencement of drilling the approximately 1,000 metre horizontal section at EP 161 (Tanumbirini #2H) began. Origin/Falcon announce a normalised gas flow rate equivalent of 5.2-5.8mmcf/d per 1,000m of lateral from the Amungee NW-1 well into the Velkerri B shale formation.

Company Assets



Source: Tamboran

Tamboran's original block is EP 161, operated by Santos and which has seen the most exploration activity to date. In December 2020 Tamboran announced the completion of the acquisition of a 100% interest in EP 136, EP 143 and EP(A) 197, which were acquired from Longview Petroleum's wholly owned subsidiary Sweetpea Petroleum. Longview received just under a 30% stake in Tamboran. Learning from the U.S. shale boom, Tamboran chose to consolidate the best parts of the basin first and is focused on a measured plan to develop the best geology and drive return on investment. The contiguous nature of EP 161 / EP 136 provides opportunity to collaborate with Santos by potentially sharing rigs/equipment/drilling learning curves to reduce costs and accelerate first development from the "Core Beetaloo"

EP 161

EP 161 has a total area of approximately 10,500 km^2 with an estimated prospective area of 2,200km^2. Tamboran was granted the exploration permit 100% in 2012, when it entered into a farm-in agreement and a joint operating agreement with Santos with the right to earn up to a 75% interest in the permit, subject to the following conditions:

- Santos spending A$41mm on exploration as its farm-in commitment for a 50% interest; and
- Santos spending a further A$3mm to complete the work programme (including drilling and testing of two wells) before the expiry of the term on 21 May 2018 for a further 25% interest.

Santos satisfied both these conditions and currently has 75% with Tamboran owning the remaining 25% non-operating interest. EP 161 is currently in the exploration and appraisal phase.

The EP 161 JV originally drilled the Tanumbirini-1 vertical well in June 2014, positioned in the basin centre, to a depth of 3,946m. It intersected the Middle Velkerri shale at 3,205m with a thickness of 433m with three zones A, B and C, which had limited faulting and superior reservoir qualities. The well was not tested until 2020, after it was fraced with four stages in Q4'19. This program was the first hydraulic fracing operation performed in the Northern Territory under the new unconventional energy rules and regulations. The Velkerri-B was the most productive at 2-3x more than the A and C zones. The B was ~120m thick with 30-40% of the interval containing high porosity (12%) and high permeability (10-20mD) rock, which is almost close to conventional quality.

Tanumbirini-1 vertical well stimulation

Fracture Treatment Stage	Target	Depth Stimulated (m)	Fluid Volume (Barrels)	Sand Placed (Ton)
1	Middle Velkerri A shale	3,585-3,591	17,554	37
2	Middle Velkerri A-B Interburden shale	3,504-3,507	10,359	150
3	Middle Velkerri B shale	3,448-3,451	10,029	158
4	Middle Velkerri C shale	3,250-3,253	9,419	151

Source: Tamboran

During Q1'20, a 130-day flow test showed a maximum flow rate of 1.6mmcf/d and settled at 0.4mcf/d with minimal decline. The flow test was ended prematurely due to the shelter-in-place orders because of COVID-19. Once the well was reopened in Q4'20 and initially flowed 10mmcf/d and achieved an average flow rate of 2.3mmcf/d during the first 90-hours of testing and 0.6mmcf/d over a 20-day period. 80% of the gas produced was estimated to be coming from the B-zone, in particular the 40m sweetspot. The natural gas contained ~3% CO_2. A "Declaration of Discovery" was accepted by Northern Territory Government in April 2020. Of note, the Amungee NW-1 well only had half the thickness of M Velkerri 'B' compared to Tanumbirini 1.

The data compiled to date from Tamboran's Tanumbirini #1 well and vertical frac indicates that horizontal wells in the Beetaloo Basin's Middle Velkerri Shale Formation have potential to be on par or better than wells in the core Marcellus Shale, currently the most prolific unconventional gas shale play in North America.

Resource potential

Following this well 116bcf of gross contingent resource was booked in the B and C reservoirs. In total there is an estimated 49tcf of prospective resource on the block of which over half resides in the Velkerri B.

Gross unrisked prospective resource on EP 161

		Gas Resources (BCF)			Condensate Resources (MMBBL)		
Area	**Reservoir**	**Low Estimate (1U)**	**Best Estimate (2U)**	**High Estimate (3U)**	**Low Estimate (1U)**	**Best Estimate (2U)**	**High Estimate (3U)**
Main	Lower Kyalla	345	867	2,697	5	18	86
Main	Velkerri C	7,372	12,842	25,648	15	80	302
Main	Velkerri B	13,041	21,739	41,692	13	110	427
Main	Velkerri A	3,190	6,138	12,776	3	31	130
East	Velkerri C	667	1,127	2,171	10	24	69
East	Velkerri B	2,684	4,363	8,163	3	22	83
East	Velkerri A	1,126	2,172	4,815	1	11	49
Total		**28,425**	**49,248**	**97,962**	**50**	**296**	**1,146**

Source: Tamboran

Appraisal campaign

The EP 161 JV currently intends to drill four exploratory wells on EP 161 during 2021 and 2022 for phase 1 and 2. The joint venture will assess the results from these wells to determine the optimal development path forward.

The Tanumbirini 2H and 3H wells are being drilled in 2021 to appraise the Mid-Velkerri 'B' shale in EP 161 and also provide critical data for Tamboran's EP 136 operated permit. Santos and Tamboran spud the T2H well on 11 May 2021. T2H reached TD at 4,598 metres depth in mid-August and is now drilling T3H to a similar TD, prior to fracture stimulating both wells. Preliminary flow test results from T2H and T3H are anticipated to be available in Q4'21. The estimated total cost for the 2021 campaign is A$67mm or A$17mm net to Tamboran. The wells are expected to have 1,000m lateral sections with 10-20 stage completions with the final number of stages likely to depend on how the budget is looking when it comes to the fracing. The forward work plan and commitments for EP 161 are set out as follows:

Period	Work Program	Commitment
2021 – phase 1	Drill Tanumbirini #2H and #3H horizontal wells, followed by flow tests on each well	Estimated costs to Tamboran's 25% interest total A$16.8mm
2022 – phase 2	Drill Inacumba #1H and #2H horizontal wells, followed by flow tests on each well	Estimated costs to Tamboran's 25% interest total A$25.1mm

Commercialisation

After the drilling program in 2022, the joint venture will evaluate the status of the wells and well tests and, subject to the results, will initiate plans for commercialisation of the license's gas resources.

EP 136

The EP 136 licence is 4,230 km^2 and lies adjacent to EP 161 in the core of the Beetaloo Sub-basin and is, based on seismic data and interpretation, on comparable interpreted geology as EP 161's successful Tanumbirini #1 discovery well. Tamboran believes the northern portion of EP 136 is within the Kyalla and Velkerri gas window. The block contains an estimated 19tcf of unrisked prospective resource. Importantly, as operator of the licence with 100% stake, Tamboran is able to drive and dictate the exploration and development. Tamboran has a three year program that anticipates completion of an extensive 2D seismic survey and the drilling and evaluation of up to nine wells.

The estimates of Tamboran's gross prospective gas and condensate resources relating to its 100% interest in EP 136 range from 11.2 Tcf to 37.8 Tcf, reflecting asymmetrical risk to the upside relative to the 'best estimate' provided. The best estimate is approximately 19 Tcf as follows (as of 31 January 2021).

Un-risked Gross	**Prospective (Bcf)**	
Reservoir	**Gas Resource**	**Condensate**
Velkerri C	6,050	50
Velkerri B	9,698	49
Velkerri A	3,037	15
Lower Kyalla	232	5
TOTAL	**19,017**	**119**

Work program as currently contemplated for EP 136

Period	**Work Program**	**Commitment**
2021 – phase 1	Extensive 250 km 2D Seismic Survey and site preparation	Approximately A$8mm
2022 – phase 1	1 horizontal well, followed by a flow test (plus long-lead items for the following year)	Approximately A$60mm
2023 – phase 2	Up to 3 horizontal wells, followed by flow tests on each well	Up to A$130mm

Tamboran's work plans include extensive 2-D seismic work principally on the northern part of EP 136 (at an estimated cost of A$3.5mm) followed by an initial exploratory horizontal well, Maverick #1H and a flow-test in 2022 (A$39.4mm estimated cost), subject to a landowner usage agreement. Given that Tamboran is the operator, the Maverick #1H well is expected to see a much longer lateral section (compared to 1,000m at the T2H well) and will likely see 35-40 stages or double the amount of T2H. Some wells in the Marcellus are now >6,000m laterals. Also, the size of each frac is expected to be larger. There should be the potential for higher flow rates from the M1H well as a result.

The aim is to establish commercial flow rates and then explore a potential farm-down of its EP 136 interest to provide funding flexibility for Maverick pilot development. After the 1st well, if successful, we would expect Tamboran to look to farm down its assets with the most likely buyer one of the LNG plant owners that are looking for more gas for either existing trains or to justify an expansion (e.g. INPEX or TOTAL).

Subject to a successful outcome during the 2022 work plan, Tamboran intends to drill up to 3 wells in EP 136 during 2023 and, if successful, sanction the construction of an EP 136 pilot plant, which will involve 8-10 wells that could produce 100mmcf/d. Following the 3-well programme, if successful, there is the potential to add 2tcf of 2P reserves.

Tamboran initally plans to sell gas produced from the 2022/23 horizontal well tests to local Northern Territory markets, transported largely through existing pipelines. Tamboran presently intends to work with Jemena on an infrastructure solution that provides a commercial pathway to supply the domestic gas market in Australia. Jemena, will construct a pipeline connecting the Beetaloo Sub-basin directly to the South East Australian domestic gas market, via Jemena's existing northern gas pipeline, and north to the Darwin LNG complex. A comprehensive drilling campaign is expected to take place through 2023 and 2024, capable of providing sustained production into the existing and planned Jemena system by 2025.

EP 143 and EP (A) 197

EP 143 is 2,090 km^2 block where Tamboran's plans consist of maintenance of the permit for future assessment. EP(A) 197 is approximately 790 km^2 adjoins a portion of the northern boundary of EP 143. Tamboran's plans for EP(A) 197 consist of completing acquisition of the licence and maintenance of the permit for future assessment. Tamboran will assess prospectivity of both blocks to determine future development opportunities.

Overriding Royalty Interests

Under section 84 of the Petroleum Act 1984, Tamboran is required to pay an overriding statutory royalty of 10% of the gross wellhead value of all petroleum produced from the Tamboran Assets.

Sweetpea Petroleum's Assets are subject to overriding royalty interests (ORRI) and an Area of Mutual Interest (AMI) obligation. The aggregate ORRI totals 7% of revenue. Portions of the 7% ORRI, may be reduced over time to an aggregate 3% ORRI, and the obligations with respect to the AMI eliminated through cash payments made by Tamboran totalling approximately US$17 million.

Sweetpea had granted an ORRI equal to an undivided 8% of 8/8ths of all petroleum produced from EP 136, EP 143 and EP(A) 197 to Tom Dugan Family Limited Partnership, LLP, Territory Oil & Gas, LLC; and Malcolm John Gerrard (together the Bayless Group).

Tamboran, as purchaser of Sweetpea, is required to assume the AMI obligation. The Bayless ORRIs may be reduced progressively over the period from 2021 to 2025 in accordance with the terms of an agreement that states reduction:

- from 4% to 2% by payment of US$7 million to the Bayless Group by 1 July 2023; and
- from 2% to 1% by payment of a further reduction payment of US$7 million to the Bayless Group by 1 July 2025.

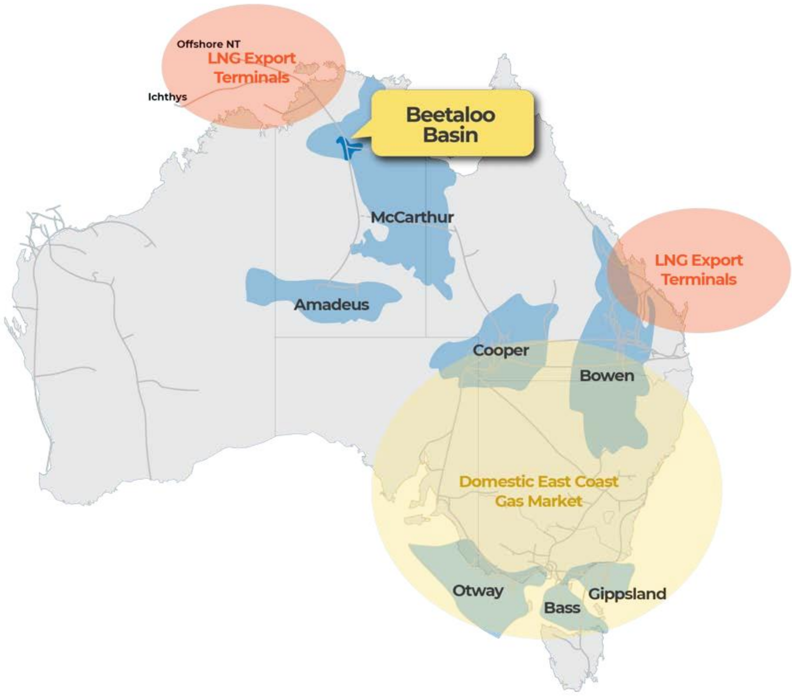
The obligation relating to the AMI may be reduced in accordance with the terms of a separate limited waiver agreement by payment of the additional amounts to the Bayless Group US$1.2 million on or before 1 July 2021.

Sweetpea has also granted PetroHunter Energy Corporation an ORRI of 2% of the petroleum produced from the land over which the EP 136 and EP 143 were originally granted and EP(A) 197 was applied for. The Petrohunter ORRI contains an option for Sweetpea to reduce the royalty to 1% on payment of US$1,000,000 to Petrohunter by 17 June 2023 and a further extinguish by agreement the remaining 1% for an amount equal to 3% of the consideration paid by Tamboran for Sweetpea.

There is also an undivided 1% ORRI in favour of Jeffrey J Rooney as trustee of the Siegel Dynasty Trust of all petroleum produced from the Sweetpea Assets and the land subject to the Sweetpea Assets.

Development and Infrastructure

Beetaloo and surrounding markets



Source: Tamboran

The growth of shale in the US overwhelmed the market causing large variations in oil and gas prices within North America and creating market dislocations. Therefore, it is important to have a plan to install the required infrastructure. Tamboran's management clearly has plenty of commercialisation experience from the US and as a result has pre-empted these issues by putting agreements in place to ensure the necessary infrastructure will be there if and when it moves to development. Australia benefits from having ample access to LNG markets through its sizeable export capacity, with easy and cheap access into the Asian market. This is a big competitive advantage versus US LNG exports of shale gas, whose transportation costs to Asia are multiple times higher.

Crucially Tamboran has lined up multiple commercialisation pathways for the gas, which is key to the value creation. It has formulated a phased, long term strategy targeting multiple markets and premium pricing. It is partnered with Santos, a major global LNG player with its own operated LNG facility within range of the basin. Australia's LNG facilities need access to large, cheap sources of gas. It has also lined up the midstream solution to bring the gas to the LNG plants. Industry-leading development costs and JV partnership with Jemena will enable Tamboran to be one of the lowest cost gas producers to the domestic market.

Jemena and Tamboran agreed on a commercial framework which provides an infrastructure solution to bring Tamboran's gas resource to market. Jemena owns and operates a diverse portfolio of energy assets across northern Australia and Australia's east coast of more than A$11bn worth of major utility infrastructure, in particular it owns and operates some of Australia's most important gas transmission pipelines. It is a private company owned by State Grid Corporation of China and Singapore Power. Jemena has an ambition to achieve net zero emissions by 2050.

Upstream

The upstream development is relatively simple especially given that it is dry gas with low levels of contaminants, (i.e. it takes little processing to bring the gas from the well head to the pipeline). Therefore, simple well head facilities are required. However, well costs are currently more than double the cost of an equivalent well in the US. While well costs are never likely to come down to this level, there is substantial room for cost savings, especially when moving into full scale development mode.

The remoteness of the play means that there is currently a high cost for mobilisation of the drilling equipment to the area (up to 25% of the well cost) and also a high cost for bringing in sand to frac the wells. There is also relatively little competition amongst service companies in Australia. If Tamboran moves into full development mode, the rig mobilisation cost will be insignificant for a multi-well drilling programme, the sand could be mined locally and it could bring a fit for purpose rig from the US with an experienced operating team. Furthermore, at present given that these are early wells into the basin and there is extensive data analysis going on, the wells are more expensive than pure development wells.

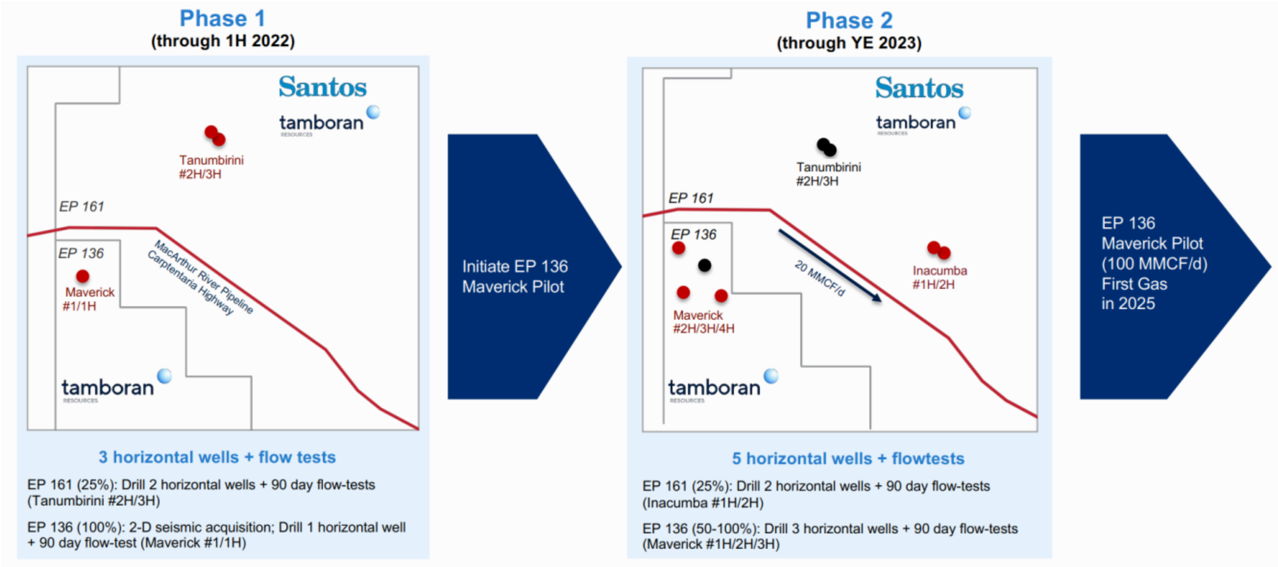
NPV10/mcf at various Australian gas prices (A$/mcf) and discount rates

		Well cost ($mm)				
		$10.0	$15.0	$17.0	$20.0	$25.0
	$0.20	0.58	0.47	0.42	0.36	0.24
Opex	$0.30	0.57	0.45	0.41	0.34	0.23
$/mcf	$0.40	0.55	0.44	0.40	0.33	0.22
	$0.50	0.54	0.43	0.38	0.31	0.20
	$0.60	0.52	0.41	0.37	0.30	0.19

Source: H&P estimates

The table above shows that a reduction in the well cost has a significant impact on the NPV of the development. This is because virtually all of the upstream capex comes from the drilling of the wells.

EP 161 / EP 136 Phased Appraisal Plan

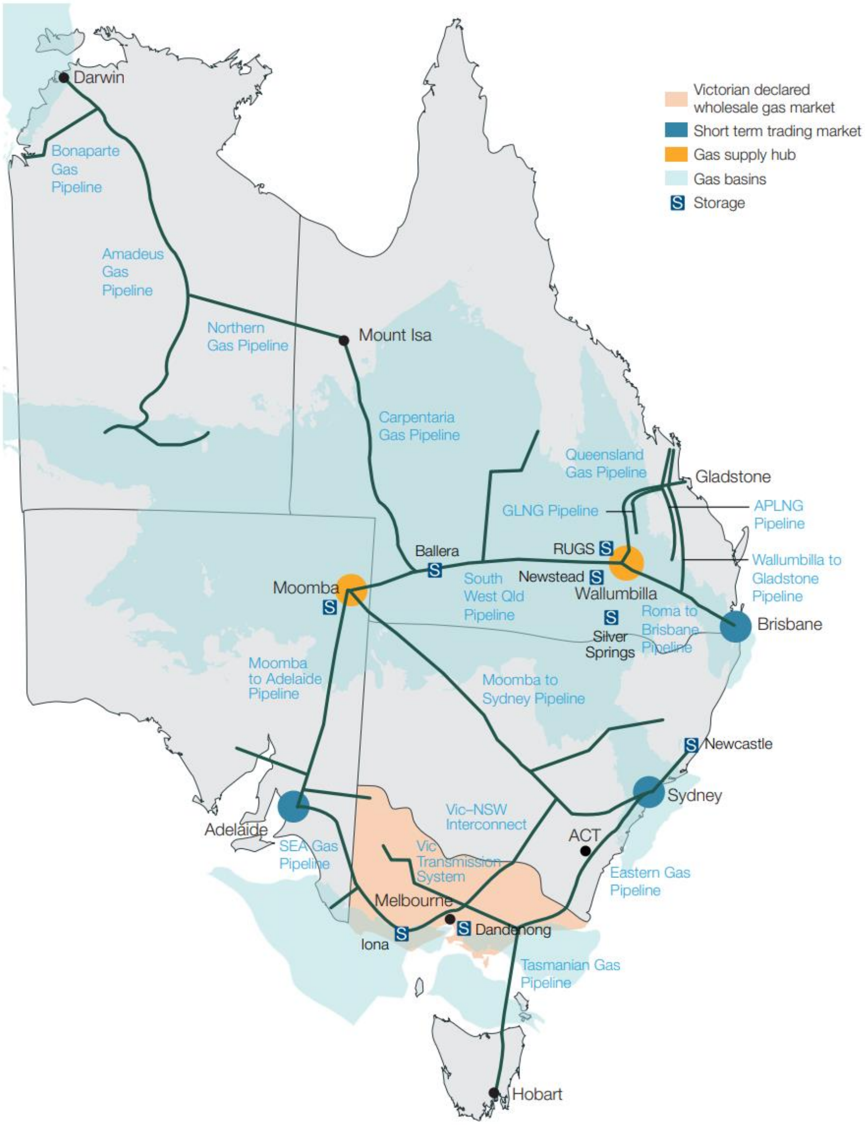


Source: Tamboran

The key objectives of the appraisal programme in the first phase to H1'22 that need to be realised to move towards development are to confirm commercial flow rates from the 3 horizontal wells planned on EP 161 and 136 and sign an early gas sales heads of agreement for ~20mmcf/d.

Phase 2 through to the end of 2023 involves the drilling of a further 2 wells (Inacumba #1H/2H) to the SE of Tanumbirini on EP 161 and to drill a further 3 horizontal wells with flow tests on Maverick to the north of EP 136. The plan would be to initiate first gas at 20mmcf/d from EP 136 and sanction the EP 136 pilot allowing the booking of 2P reserves (e.g. a 15 year contract for 20mmcf/d would allow ~100bcf of 2P reserves to be booked). There is also the intention to sign a heads of agreement with Jemena for 100mmcf/d with first gas in 2025. A comprehensive drilling campaign is expected to take place through 2023 and 2024, capable of providing sustained production into the existing and planned Jemena system by 2025.

Infrastructure
Eastern gas basins, markets, major pipelines and storage



Source: AER; Gas Bulletin Board

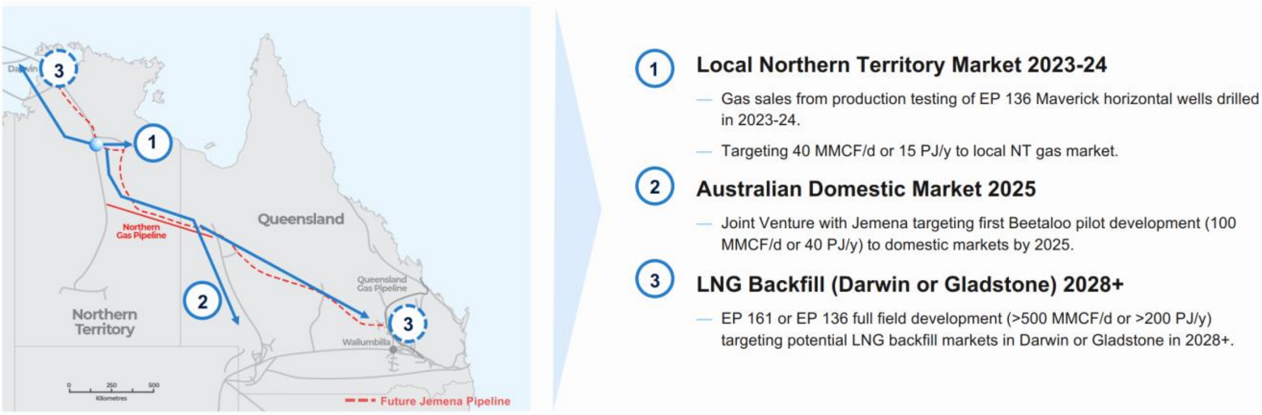
Tamboran will aim to formalise the commercial infrastructure arrangement that has been agreed with Jemena. This provides for the construction of a pipeline connecting the Beetaloo Sub-basin directly to the South East Australian domestic gas market, via Jemena's existing Northern Gas Pipeline, and north to the Darwin LNG complex. Existing and planned pipelines connecting the Beetaloo Basin to SE domestic market and multiple LNG plants in Darwin and East Coast Australia.

The ACCC forecast potential for a domestic gas supply shortfall of 75mmcf/d to emerge as early as 2024, in addition to 250mmcf/d of East Coast LNG that will remain under-utilised unless speculative resources are developed.

In 2020, Tamboran and Jemena agreed on a detailed commercial framework to form a Joint Venture for Jemena to build, own, and operate long term midstream gas infrastructure. Jemena plans to construct an initial pipeline directly connecting Tamboran's Core Beetaloo Basin resource to SE Australian Domestic Gas Market via Jemena's existing Northern Gas Pipeline.

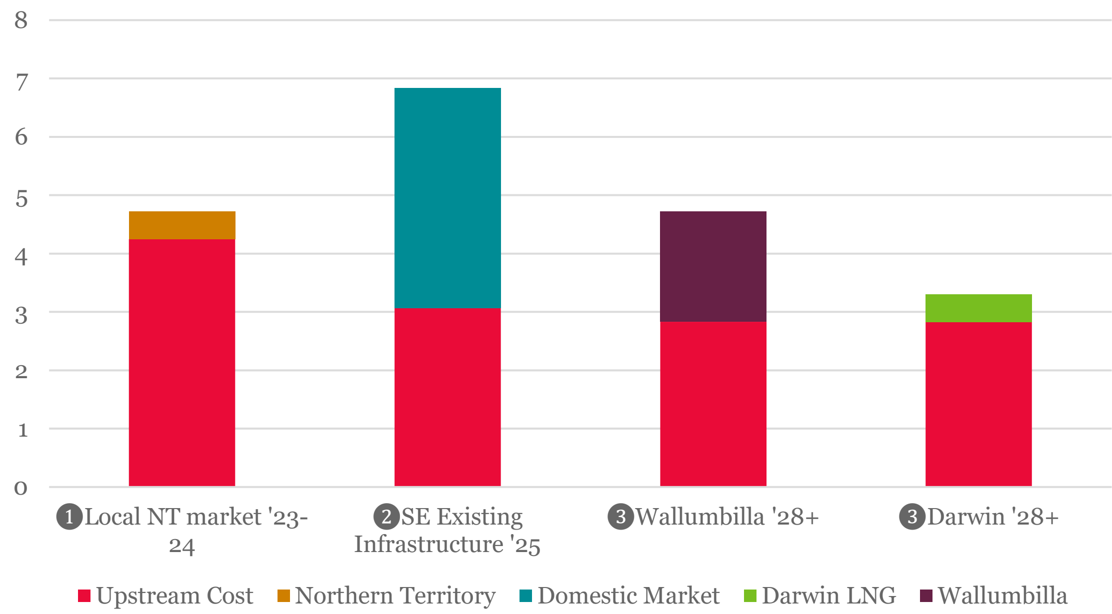
Gas commercialisation

Gas commercialisation options



Source: Tamboran

Targeted Full-Cycle Cost from EP 136 for Target Markets (A$/mcf)



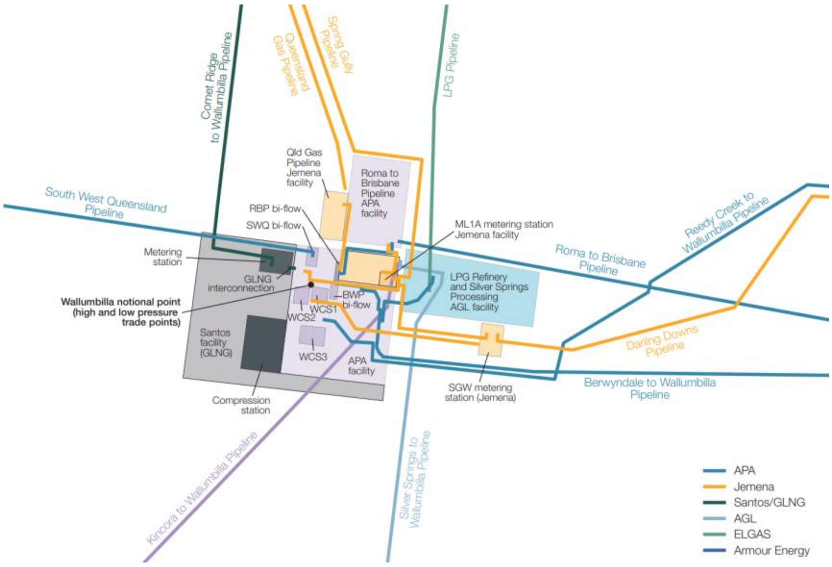
Source: Tamboran

1. Tamboran plans to sell gas produced from the 2022/23 horizontal well tests to local Northern Territory markets, transported largely through existing pipelines. The gas would be sold initially on a spot basis and, once consistent delivery has been established, under long term contract with Northern Territory gas users. The local market in the area requires around 40mmcf/d of gas and can be supplied through the existing 20mmcf/d McArthur River pipeline, which could potentially be expanded to 30mmcf/d.

2. Once prospective resources identified in EP 136 are proven up, Tamboran intends to secure long term domestic gas offtake agreements and then sanction a pilot development. In the second stage of commercialisation the aim is to produce ~100mmcf/d from the pilot development of the Beetaloo and supply the existing SE domestic market

by around 2025. The intention is to connect into the existing Northern Gas Pipeline (NGP), which has a capacity of ~90mmcf/d with the potential for this to be doubled with compression. A new north-south pipeline from the Beetaloo could tie-in around 150km along the NGP. The NGP supplies the ~80mmcf/d Mount Isa market and connects into the existing network. The estimated midstream investment required for this is ~A$900mm. The estimated pipeline transportation cost to bring the gas to market is high at A$4/mcf but it allows a faster timeline to market ahead of Jemena building new pipelines to Darwin and/or Wallumbilla.

Wallumbilla hub



Source: AER, accounting for consultations with APA Group and public information supplied by APA Group, Santos, AGL, the Queensland Government, Geoscience Australia and AEMO

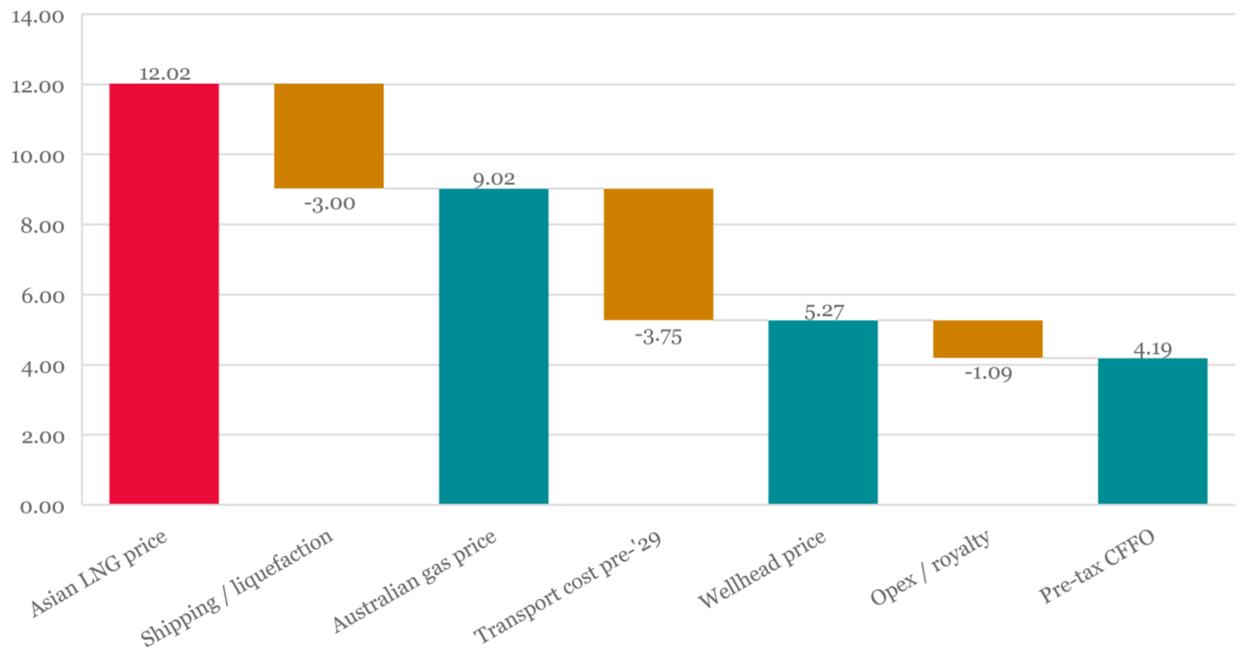
3. In the longer term, Tamboran intends to move to full field development and, in addition to supply to local markets, also provide gas to LNG plants located in Darwin and/or the east coast of Australia to meet increasing LNG demand from Asia. The plan would be to extend and expand the NGP pipeline to the key gas hub of Wallumbilla (equivalent to Henry Hub in the US) with a capacity of ~1bcf/d. Wallumbilla is a major pipeline junction linking gas basins and markets in eastern Australia, making it a natural point of trade. Origin/Santos have major stakes in GLNG/APLNG plants in Queensland too. There is expected to be a further shortfall of gas for the SE market and the Queensland LNG plants later this decade. The estimated investment required for this would be A$5bn according to Jemena, however the pipeline tariff for Tamboran will be much lower (potentially A$2/mcf) given the much higher volumes that can be put through dedicated pipelines.

   The cost of a new pipeline to Darwin would be significantly cheaper at ~A$800mm but this would require an expansion of the Darwin LNG facility to accommodate further gas volumes. There is the potential for Tamboran to acquire a direct stake in the Darwin LNG plant over time to then be able to put its own equity volumes into the plant and offer to sell LNG directly to global customers. Darwin LNG has authorisation to be expanded with the addition of a further LNG train.

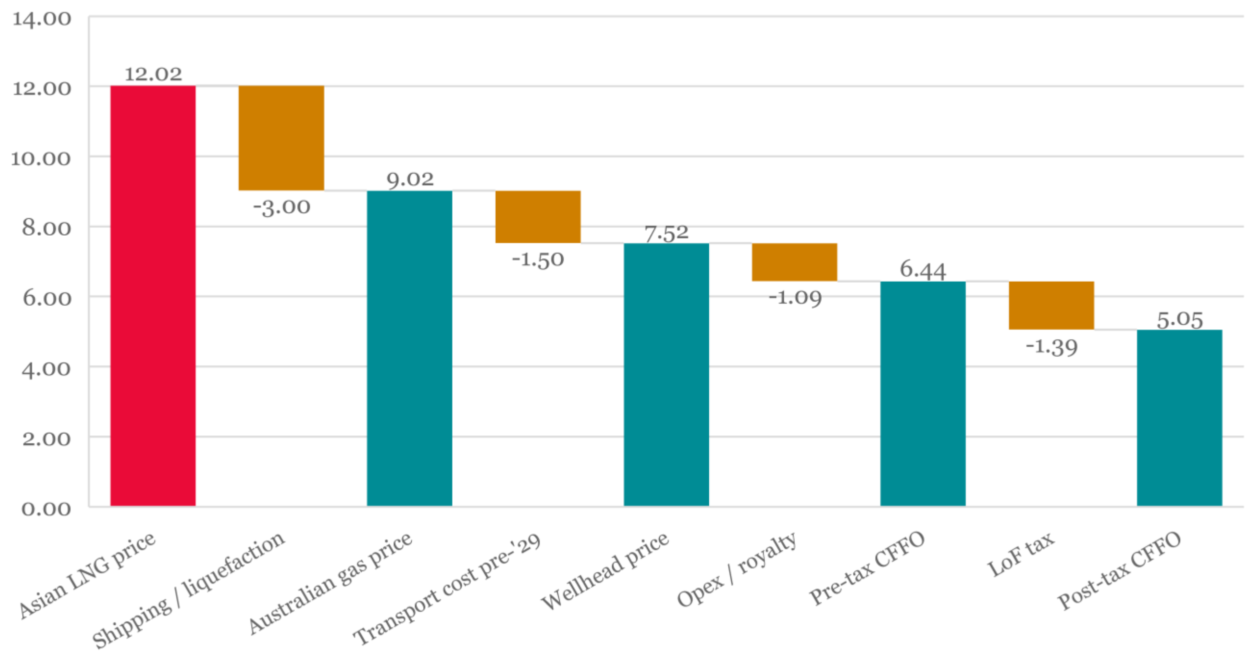
Gas prices and realised prices

The charts below show the route to the netback that Tamboran will receive based on our base case Asian LNG price of A$12/mcf. The top chart for the near-term assumes a higher transportation cost of A$3.75/mcf before the new pipeline infrastructure lowers costs to A$1.50/mcf from 2029. Also we assume minimal tax payable in the short term. Over the life of the field we estimate capex of A$1.4/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

Development scenarios and economics

Given that Tamboran is still in the exploration/appraisal phase on its acreage, we believe that it makes sense to come up with potential development scenarios and then put a risking on these for the EP 136 and EP 161 licences.

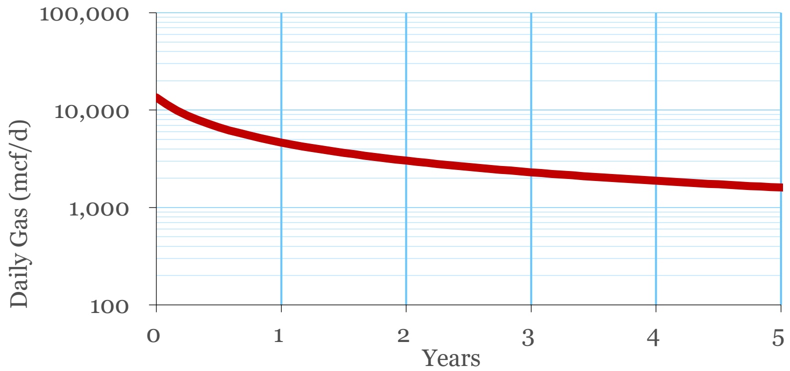
Given the size of the prospective resource being targeted and the low risk nature of the exploration as this is a shale resource play, we do not think that the size of the resource will be a constraining factor on development. We do put a risking on the exploration to factor in some risk of the geology turning out to be worse than expected. We have a lower risking on EP 161 (75% geological chance of success) given that there has been a vertical well tested already on the acreage and contingent resource has already been booked. For EP 136 we use a higher risking (50% geological chance of success) given that there have been no wells drilled on the block.

We expect that one of the limiting factors over time for production from the Beetaloo could be takeaway capacity out of the basin. We assume that the EP 136 and EP 161 licences will be able to produce around 0.5bcf/d, which is around half of the planned capacity out of the basin by the end of the decade. Tamboran's deal with Jemena means that it will have access to 0.5bcf/d of capacity on the planned pipelines. From a Tamboran perspective it would make sense to send higher volumes from EP 136 given that it has a 100% stake, however to be conservative we have assumed that 250mmcf/d will be produced from each licence.

Although EP 161 is ahead in terms of the drilling campaign, we assume that a 100mmcf/d pilot from EP 136 is developed first, given Tamboran's move to rapidly develop the block if successful next year with its exploration programme. We assume a 75% chance of commercialisation for the pilot production stage. We then use a higher risking (50% chance of commercialisation) for the incremental 150mmcf/d growth on EP 136 to factor in risks around the infrastructure being built and funding. For EP 161 we assume a 250mmcf/d development and use a 75% chance of commercialisation

For the pilot development to reach around 100mmcf/d, in our base case assumptions for development we assume a well cost (drill, complete and tie-in) of A$17mm per well, with an average IP (initial production) rate of 13.5mmcf/d and EUR (recovery per well) of 12.5bcf. This is based on a 3,000ft lateral with 40 frac stages. This works out to an overall upstream development cost of ~A$1.5/mcf. Operating costs are expected to be A$0.40/mcf. Therefore, the total cost to bring the gas to the pipeline entry point is around A$2.0/mcf. For the pilot development we assume a A$3.75/mcf total pipeline tariff, which means that the delivered gas price is ~A$6/mcf.

Estimated single well production profile (log scale)

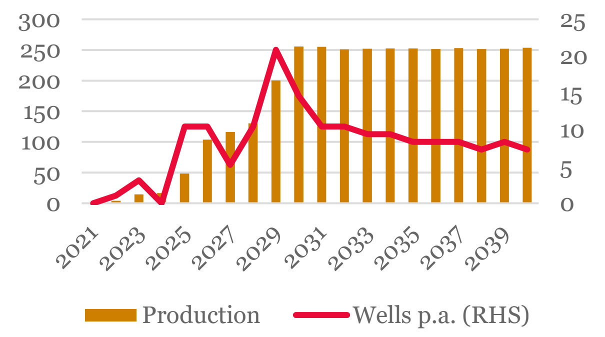


Source: H&P estimates

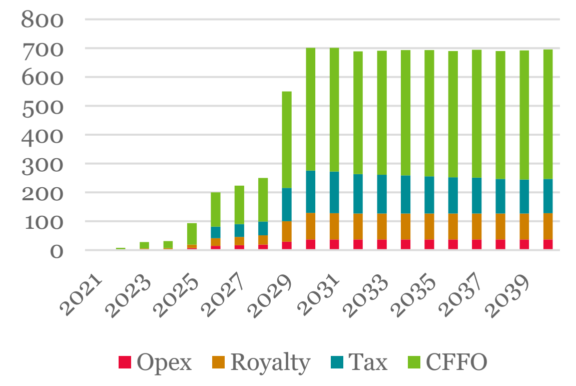
EP 136 development scenario

We have looked at the scenario where production from EP 136 grows to ~250mmcf/d. The charts below show the key data to 2040 for production and the elements of cash flow as well as sensitivities to different gas prices.

Production profile (mmcfe/d) and wells drilled



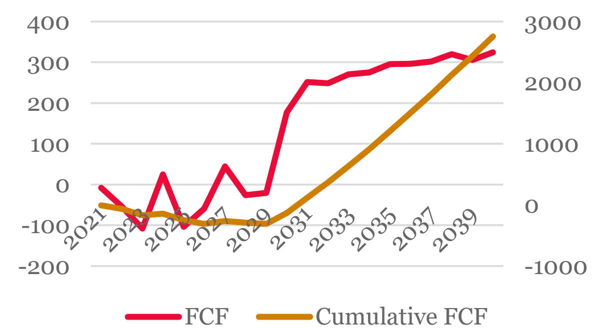
Split of revenue (A$mm)



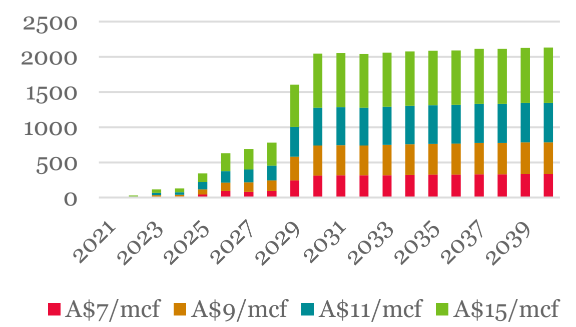
Source: H&P estimates

The production profile above is reflective of at first being capacity constrained and then ramping up the well count from 2028 to grow production to 250mmcf/d and then cutting down the number of wells required p.a. to a maintenance level of less than 10. The righthand chart shows the split of revenue at our base case Australian LNG netback price of A$9/mcf. The realised price and revenue jumps in 2029 as we assume the gas is transported through a new lower cost export route.

FCF and cumulative free cash flow (A$mm)



CFFO at various Australian gas prices (A$mm)

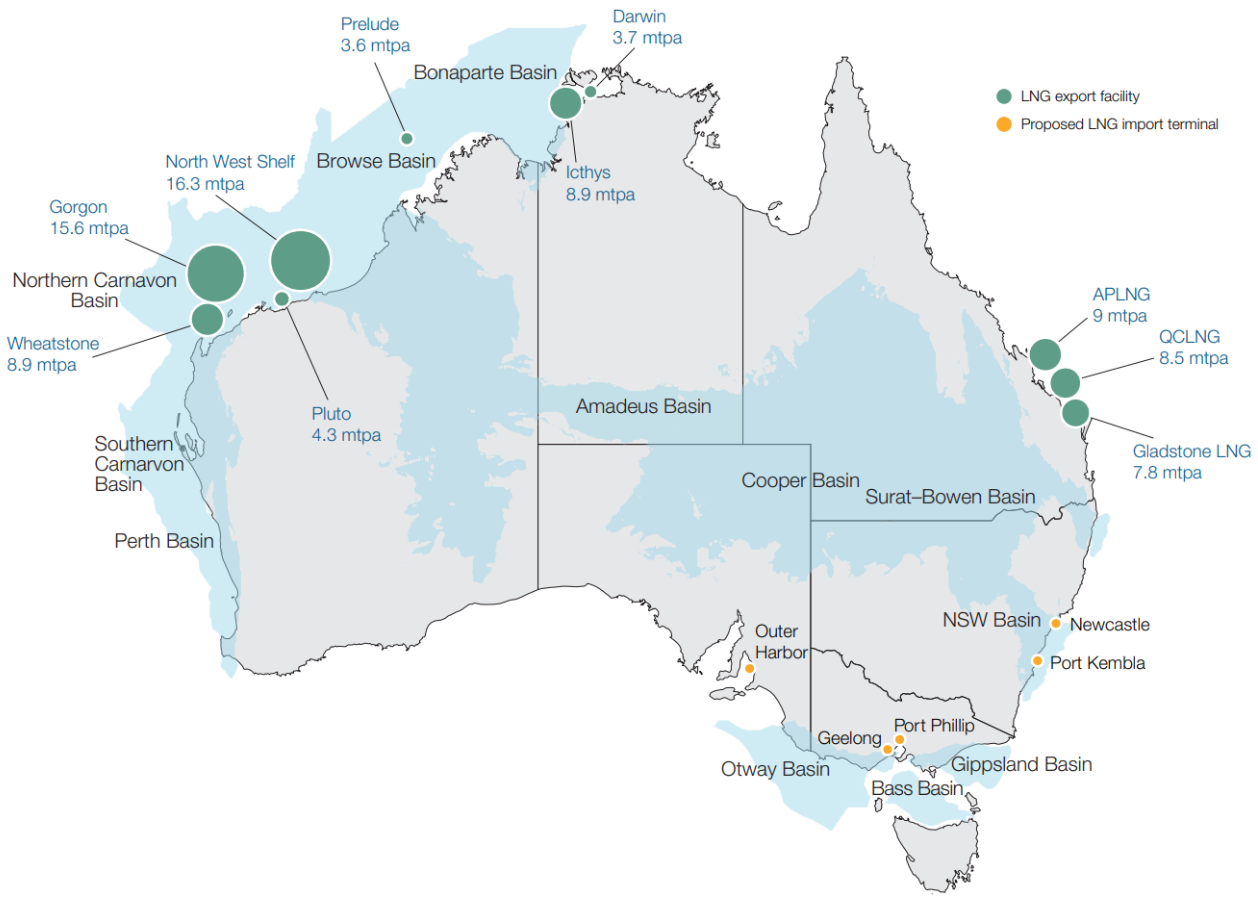


Source: H&P estimates

The left-hand chart shows that the project is FCF negative for several years before reaching plateau production at the end of the decade and the subsequent FCF generation of >A$250mm per annum and cumulative FCF reaching almost A$3bn. We see the maximum net spending requirement as <A$500mm as cash flow will start being generated potentially as early as next year. The right hand chart shows the sensitivity of the project's cash flows to gas prices. It remains cash flow positive even with Australian gas prices of A$7/mcf and there is the potential to generate >A$2bn per annum in CFFO if Australian gas prices reach A$15/mcf.

Australian LNG's competitive advantage

Australia's LNG export projects and capacity



Source: AER

Although Australia is associated with cost blow outs, it has a few major advantages over greenfield LNG projects elsewhere.

- **Infrastructure:** First, after a $200bn spend, there is ample existing infrastructure to be used that new developments can backfill with minimal downstream costs. For example, the North West Shelf partners have suggested a US$2.10/MMBtu toll for future production into the plant, which at the low end of the range of tolling fees being offered in the US. There is also the opportunity for brownfield developments (e.g., Pluto T2 will be much cheaper than T1).

- **Shipping cost:** The shipping distance from Australia, into the key demand markets of Asia leads to a significant cost saving versus projects from the Americas, Northern Russia or West Africa. At a day rate of $75,000, we estimate ~US$1.50/MMBtu saving shipping LNG from Australia to China versus from the US GoM.

- **FCF generation:** Crucially the existing LNG projects throw off substantial FCF that than be re-invested into further projects. Australia will be exporting >4Tcf a year of LNG: worth about $40bn including liquids at $8/MMBtu LNG pricing and $60/bbl Brent and we estimate FCF to the companies will be >50% of this or $20bn after costs and taxes.

- **More spot volumes:** Existing cashflow and the use of existing facilities means that there is less need to secure long-term contracts on the vast majority of LNG volumes, making projects easier to sanction.

Brand new greenfield onshore or large scale FLNG projects do not appear viable but there are much lower cost opportunities for debottlenecking at existing plants (e.g., most plants have shown the ability to run at >10% of nameplate) and there is room for cost effective expansions at existing plants being studied (Darwin and Pluto). The most likely expansions are at Pluto, Darwin and Ichthys with the potential to also add more trains at Gorgon and Wheatstone further down the line. Expansion costs should be much more reasonable and globally competitive than the initial greenfield projects. For example: Woodside estimates a $700/t expansion cost at Pluto vs. the initial >$2,000/t cost for the first train.

LNG markets for Beetaloo gas

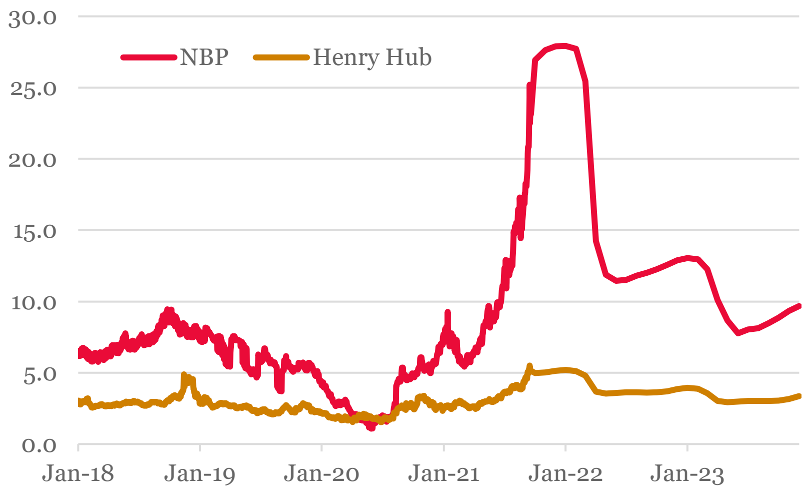
The 3.7mpta Darwin LNG plant started in 2006 and the key field supplying the plant is expected to be depleted shortly with Santos having sanctioned the Barossa field development to provide backfill volumes to the plant. There is the potential to expand Darwin to up to 10mtpa with a feasibility study funded by resource owners in the area. There is also room for 4 more LNG trains at the nearby 8.4mtpa Ichthys plant. Planned production from the initial phase of Ichthys will reach 1.2bcf/d but in phase two there is a suggestion the design rate will be increased to 2.4bcf/d.

The Queensland LNG projects have failed to live up to expectations with both reserves and investment write-downs. The three Queensland CBM to LNG facilities are now fully online with a total nameplate capacity of 25mmtpa, however these plants have been producing at lower than this due to lower than expected supply from GLNG's upstream, QCLNG had a reserve write-down too and domestic demand has surprised to the upside. However, the actual plants, all built by Bechtel have shown the ability to produce at around 10% above nameplate capacity. The upstream for these fields is different from a conventional project in that there needs to be continuous intensive drilling of wells, to offset the decline, from the high decline CBM wells. Also, the core of the plays have now been drilled up so the companies are having to move to lower tier and lower productivity acreage.

We estimate that the plants produced at 80% of capacity in 2020 – reaching 110% of capacity would imply the potential for an extra 7.6mmtpa of LNG. Santos is operator of Gladstone LNG (GLNG) in Queensland and could do with new supply to move up to nameplate capacity. GLNG has suffered from poorer than expected upstream performance that has led to the facility having to rely heavily on third party gas and even so producing well below its potential. The project focus has been to reach 6mpta and now with visibility on this, we expect Santos to focus on finding ways to utilise the spare capacity: GLNG's ullage to 8.4mtpa potential capacity (assuming 10% upside to nameplate) provides opportunities for organic and inorganic growth.

Global gas markets

US and European historical and futures gas pricing ($/mcf)

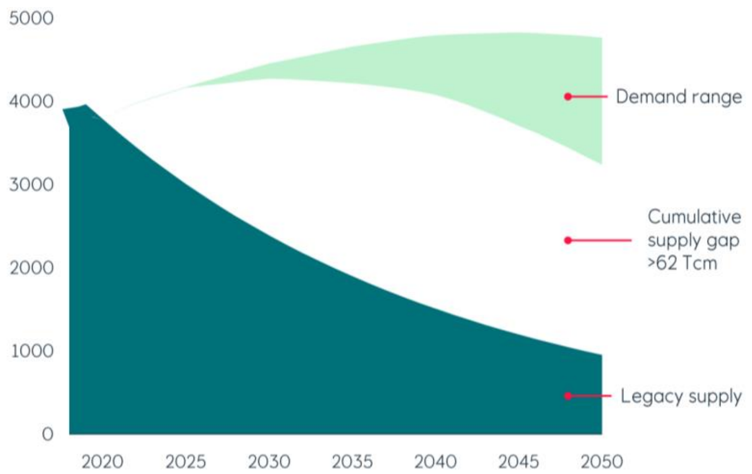


Source: S&P Cap IQ, H&P estimates

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. Being close to high growth and high demand Asian markets such as Japan, Korea, and China enable lower transport costs and therefore confers a unique benefit to the Australian LNG producers.

We believe that Australian gas prices are biased higher for several reasons. Global LNG and spot gas prices are influenced by higher oil prices (e.g. majority of LNG still priced off crude) and Australian gas prices are influenced by the LNG export netback given the strong export volumes. The futures curves for UK gas prices (NBP) and for Asian LNG prices are extremely strong and could drag Australian prices up further (see chart above). Globally a lack of investment into gas developments, cancellation of LNG projects and continued growth (especially China) is leading to higher demand and prices as demonstrated by the long-term supply gap that needs addressing shown on the chart below.

Global gas supply and demand from existing fields (bcm)



Source: Equinor

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Company History

Tamboran was founded in 2009 and is headquartered in Sydney, Australia. Previously, Tamboran held interests in exploration permits and applications in the Northern Territory, South Australia, Western Australia, Turkey, Myanmar, the United Kingdom, Northern Ireland and Botswana. During the period from 2014 to early 2016, Tamboran chose to focus on the Northern Territory and relinquished or divested its rights to explore in other jurisdictions.

2020

- **May**: Tamboran agreed to acquire Longview Petroleum's 100% interest in neighbouring EP 136 (previously owned by Paltar/Sweetpea).

- **October:** Tamboran announced successful test result of the Tanumbirini #1 vertical frac and flow test with Santos in the Beetaloo McArthur Basin with flow tests achieved of up to 2.3mmcf/d.

- **November:** Tamboran signed a Memorandum of Understanding with Jemena, that will increase the Northern Gas Pipeline's capacity. As part of the agreement, Tamboran will be responsible for upstream activities across the basin.

- **December**: Tamboran acquired Sweetpea Petroleum in an all share transaction expanding resource holdings in the core of the Beetaloo Basin. It regained its 100% Working Interest as owner and operator. Institutional investors funded A$10mm in a private placement.

2021

- **March:** Tamboran announced changes to its board. Appointed Dick Stoneburner as Chairman and Ann Diamant as a new Non-Executive Director. Patrick Elliott stepped down as Chairman.

- **May:** Tamboran released its inaugural Sustainability Plan, outlining Tamboran's wide-ranging set of commitments to achieve its vision of playing a part in the global energy transition to a lower carbon future.

- **May:** Tamboran downsized its offer from A$80mm at 40¢ a share to A$60mm at the same price. Firm IPO commitments totalling A$60mm for 150mm shares were received from existing shareholders and new investors.

- **May:** Commencement of drilling the approximately 1,000 metre horizontal section at EP 161 (Tanumbirini #2H) began.

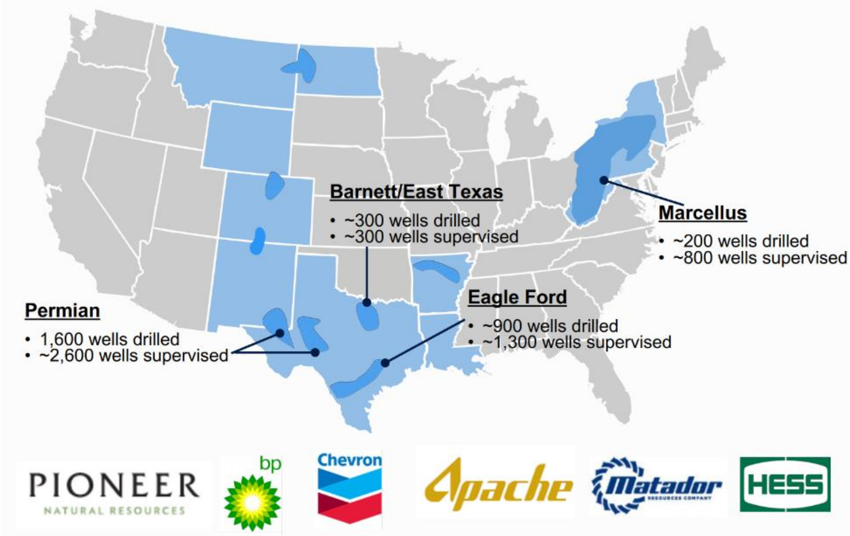
- **July**: Tamboran started trading on ASX following a successful initial public offer which raised A$61mm at 40 ¢ a share. Commencement of drilling the approximately 1,000 metre horizontal section on Tanumbirini #2H.

- **August:** Tanumbirini 2H successfully drilled to a total depth of 4,598 metres, encountering significant gas shows and pressures that are typically strong indicators of commercial flow rates. Tanumbirini 3H well ("T3H") was spudded on 23 August 2021.

- **September:** Early in the month, T3H was ahead of schedule with the completion of the surface vertical hole section at 1,080 metres.

Management Profiles

Tamboran's US Shale Operating Experience by Basin & Operator



Source: Tamboran

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. 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 have been recruited from leading US E&P companies and have over 200 years of combined US unconventional experience. In August 2021, Tamboran reported that five unconventional gas experts previously with Pioneer Natural Resources, the largest producer in the Permian Basin, United States, joined Tamboran's technical and operational team. During the same period, Tamboran hired Faron Thibodeaux as COO who served as APA Corporation (NYSE: APA, formerly Apache) as the Senior Region Vice President of APA's operations in the Permian Basin. He previously managed APA's high impact projects such as the Permian Basin, offshore Suriname and Guyana, and Northwest Shelf of Australia. The new highly experienced technical and operational professionals have collectively drilled more than 5,000 unconventional horizontal shale wells in the US.

Tamboran is headquartered in Sydney, Australia and has an international management team who have extensive experience in the successful commercialisation of large-scale unconventional oil and gas in North America. The team brings a wealth of knowledge to Tamboran, particularly relating to shale reservoir assessment and cutting-edge drilling and completion design technology. Tamboran intends to leverage its extensive skill-base to reduce drilling and development costs, optimise the development footprint and mitigate environmental impacts.

A key to success in US shale plays has been drilling wells without any drilling issues, using the latest technology and at the lowest possible cost. The 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.

Board of Directors & Key Management

Name	Profile
Mr. Dick Stoneburner, Chairman - Tamboran, September 2014	• He has 35-plus years' experience in petroleum geology. • He is a former co-founder, President and Chief Operating Officer of Petrohawk Energy Corporation and President – North America Shale Production Division for BHP Billiton Petroleum. • Prior to co-founding Petrohawk, Mr. Stoneburner was Vice President, Exploration, for 3Tec Energy Corporation and worked for several E&P companies, including Hugoton Energy Corporation, W/E Energy Company, Stoneburner Exploration Inc and Texas Oil & Gas. • Mr. Stoneburner has a Bachelor of Science (Geological Sciences) from the University of Texas, a Masters of Science (Geology) from Wichita State University and has most recently been a member of the American Association of Petroleum Geologists' Distinguished Lecturer Series, 2013. • He is currently a director of several oil and gas exploration and production companies.
Mr. Joel Riddle, Managing Director and CEO, October 2013	• He has more than 17 years' experience in the upstream oil and gas industry and was previously with Cobalt International Energy, where he worked closely with executive management in the initial evaluation and implementation of the exploration growth strategy in the Gulf of Mexico and West Africa. • Played an instrumental role in Cobalt's $1 billion initial public offering in 2009 and subsequent capital raising efforts in 2010 and 2011. • Mr Riddle also served various technical and leadership roles at ExxonMobil, Unocal and Murphy Oil. • Mr Riddle holds a Bachelor of Science with Honours in Mechanical Engineering from the University of Florida and a Master of Business Administration from the University of Chicago.
Mr. Eric Dyer, Chief Financial Officer November 2019	• Mr Dyer has over 20 years of experience in finance in the energy, infrastructure and sustainability sectors. • Mr Dyer served as Head of Energy at EAS Advisors for 10 years. • Prior to EAS Advisors, he served in various investment banking and capital markets roles with firms like Atlantic-Pacific Capital, Execution LLC and IHS Markit. • He served in Fixed Income Capital Markets of the Royal Bank of Canada. • He holds a Bachelor of Science, Finance degree from the University of Minnesota.

Name	Profile
Mr. Faron Thibodeaux, Chief Operating Officer, September 2014	• Mr Thibodeaux has 40 years technical and operations experience in the energy industry. • Mr Thibodeaux previously held the position of Vice President of Drilling, Completions and Engineering of Apache Corporation. • He was formerly General Manager for Apache Australia and a board member of the Permian Basin Petroleum Association. Prior to working with Apache, Mr Thibodeaux worked for Chevron. • He holds a Bachelor of Science, Petroleum Engineering from the University of Louisiana at Lafayette and an Advanced Management Degree from the University of Chicago Booth School of Business Executive Education.
Mr. Fred Barrett, Director (Non-Executive) September 2014	• He is an oil and gas professional and entrepreneur who recently retired from Bill Barrett Corporation, an exploration and production company he helped found in 2002 and which is listed on the New York Stock Exchange. • Mr. Barrett spent 12 years at Bill Barrett Corporation where he was instrumental in its growth into a 300+ employee organization and its successful float on the NYSE. • He acted as President and as an executive director of the Company through 2006, and CEO, Chairman of the Board and President from 2006 to 2013. • Mr. Barrett has extensive technical and geological expertise in unconventional resources and a deep commercial understanding of the shale gas industry. • He has a Bachelor of Science (Geological Sciences) from Ft Lewis College, a Masters of Science (Geological and Earth Sciences/Geosciences) from Kansas State University and an Advanced Management Degree from Harvard Business School. • Mr. Barrett has previously worked for The Williams Companies, Barrett Resources and Terred Oil.
Mr. Dan Chandra, Director (Non-Executive), April 2019	• Dan is currently a senior investment professional at Lion Point Capital, a value-focused investment fund based in New York City. • He has over seventeen years of investing experience across a range of industries and in equity, credit, and distressed debt. • Dan previously worked as a senior analyst and portfolio manager at DW Partners and at DW predecessor Brevan Howard. • Dan received an AB in Economics from Stanford University and a Master of Business Administration from The Wharton School, University of Pennsylvania.
Ms. Ann Diamant, Director (Non-Executive), March 2021	• She has more than 35 years' experience in the oil and gas and investment banking industries. • Ms Diamant joined ASX-listed Oil Search Limited in 2003 and was responsible for developing and implementing the Company's highly regarded investor relations strategy. • From 2010 to 2019, in addition to Investor Relations, she was also head of the Corporate Communications and Media Relations functions. • Before Oil Search, Ms Diamant was Investor Relations Manager at Orogen Minerals Limited and held various other positions in investment banking and finance, including Head of Equities Research for SBC Australia and Head of Oil and Gas, Utilities Research for HSBC Securities Australia. • Ms. Diamant has a BSc Hons (First Class) in Colour Chemistry from the University of Leeds and an MSc, DIC in Management Science from Imperial College, London. • In 2015, she was appointed a Fellow of the Australian Investor Relations Association (AIRA) and served as a member of the AIRA Capital Markets Committee in 2018 – 2019 and the AIRA Best Practice Guidelines Revision Working Group in 2020.

Name	Profile
Mr. Patrick Elliott, Director (Non-Executive), 2009	• Mr. Elliott established Tamboran in 2009 and is a company Director (Non-Executive). • He is formerly the founder and Director of Eastern Star Gas and SAPEX Limited, both highest successful oil and gas exploration ventures in Australia. • He also served as Chairman of Meerkat Energy Pty Ltd and Managing Director at Gold Fields Morgan Grenfell. • Mr Elliott holds a Bachelor of Commerce (Accounting and Financial Systems) from the University of New South Wales and a M.B.A. (Mineral Economics) from Macquarie University.
Mr. David Siegel, Director (Non-Executive) March 2021	• Mr Siegel is the Chairman and Managing Member of Longview Petroleum, LLC, one of Tamboran's largest shareholders. • He currently serves as a Senior Advisor to Apollo Global Management, one of the world's largest and most successful private equity firms. He also serves as the Chairman of two Apollo portfolio companies, Sun Country Airlines and Volotea, S.A. • For the past 25 years, Mr. Siegel has served as Chairman and/or CEO of several leading aviation companies including: AWAS (aircraft leasing); Frontier Airlines; XOJET, Inc. (private aviation); Gategroup, A.G.; US Airways Group; and Continental Express. Mr Siegel also served as the Chairman and CEO of Avis Budget Group. • He began his career as a consultant at Bain & Co. Mr. Siegel served for 12 years on the Advisory Board of Trilantic Capital Partners, formerly Lehman Brothers Private Equity, a leading investor in unconventional oil and gas. • Siegel earned an M.B.A., with honors, from Harvard Business School and Sc.B., magna cum laude, in Applied Mathematics-Economics from Brown University.
Mrs. Joanna Morbey, Company Secretary B.Comm (UNSW) CA	• Mrs Morbey is a member of the Institute of Chartered Accountants Australia and New Zealand has over 30 years' experience in accounting and company secretarial duties in the investment banking, property development and mineral exploration industries.

Source: Company Website, Report, and LinkedIn

Investment Risks

Tamboran like all the companies in the oil and gas industry faces general risks, including inflation, geopolitical risks, ESG and safety risk, etc. Along with these risks, there are a set of other company specific risks to Tamboran which are detailed below:

- **Access to Funding:** Tamboran has no operating revenue. As is typical for exploration companies that do not have cash generating businesses, Tamboran's ability to meet its on-going operating costs and capital expenditure requirements will ultimately involve expenditure that exceeds the estimated cash resources that Tamboran is expected to have. There can be no assurance that Tamboran will be able to obtain funding as and when required on commercially acceptable terms, or at all. Failure to obtain funding on a timely basis and on reasonably acceptable terms may also cause Tamboran to miss out on new opportunities, delay or cancel projects, or to relinquish or forfeit rights in relation to Tamboran's assets, adversely impacting its operational and financial performance. Tamboran will require further funding for the appraisal and development of its acreage from 2023, which means there is the risk of equity or asset level dilution, although farming down after the drilling campaign is part of Tamboran's strategy.

- **Cost inflation:** There is a risk that with higher oil and gas prices and also rising commodity prices (e.g., steel), that cost inflation comes through, especially with regards to higher capital costs. We think that this risk is mitigated by the strong economics at current gas prices and if gas prices do retreat from here, this will likely eliminate any upward pressure on costs.

- **Counterparty exposure and joint ventures:** The financial performance of Tamboran is subject to its various counterparties or joint venture partner (i.e. Santos) ability to perform its obligations under the relevant contracts and the EP 161 JV. If one of its counterparties or Santos fails to perform their contractual obligations, it may result in loss of earnings, termination of other related contracts, disputes and/or litigation of which could impact on the Tamboran's financial performance. On Block 161, Tamboran does not have operational control so there is a risk that the operator Santos focuses elsewhere, slowing the development potential; however Tamboran has its own 100% owned block EP 136 where it is in control of its own destiny.

- **Reliance on gas development and production activity:** Tamboran is an explorer and developer of hydrocarbons, with a focus on natural gas development in Australia. The level of activity in the gas industry may vary and is principally affected by the prevailing or predicted future gas prices, market demand and other factors. These factors can deeply impact the profitability of Tamboran, especially its top line. However the expected low cost of production means that the Beetaloo play could potentially work at low prices in case of a severe deterioration in the gas market.

- **Decommissioning risk:** Decommissioning costs may be incurred at the end of the operating life of gas assets. The exact decommissioning costs are uncertain and can vary due to a number of factors, including changes to legal requirements, new restoration techniques or experience at other sites.

- **Land access risk:** Immediate access to the licences in which Tamboran has an interest, cannot in all cases, be guaranteed. Tamboran may be required to seek the consent of landholders or other or groups with an interest in the real property encompassed by the licences. Compensation may be required to be paid by Tamboran to stakeholders to allow Tamboran to carry out activities. Although Tamboran has budgeted compensation payments, there is no guarantee that additional amounts may not be required. Judicial or regulatory decisions and legislation could also unforeseeably restrict or delay land access.

- **Growth strategy and net zero emissions risk**: There is a risk that Tamboran may fail to execute its proposed growth strategy, which includes:
  - De-risking the prospective resources identified within its highly prospective acreage in the Beetaloo Sub-basin including the Tamboran Assets;
  - Working with infrastructure partners such as Jemena to bring resources to market to meet anticipated domestic gas shortfalls and commercialising those resources; and
  - Adopting sustainable practices including a vision of achieving net zero emissions.

- **Exploration risk:** Key to Tamboran's financial performance is to have success in exploring for and locating commercially exploitable hydrocarbons. Exploration is subject to technical risks and uncertainty of outcome. Tamboran may not find any or may find insufficient hydrocarbon reserves and resources to commercialise, which would adversely impact the financial performance of Tamboran.

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