tamboran
RESOURCES

NYSE: TBN, ASX: TBN

North American Non-Deal Roadshow Presentation

September 2025

SHENANDOAH SOUTH WELLPAD, NORTHERN TERRITORY, AUSTRALIA

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This presentation was approved and authorised for release by Mr. Dick Stoneburner, Chairman and Interim Chief Executive Officer of Tamboran Resources Corporation.

Investment highlights

Significant gas development in the Beetaloo Basin, with potential to become a world class gas province[1]

1. **Significant unconventional gas resource**
   Beetaloo Basin resource properties compare favourably with leading unconventional Marcellus plays

2. **Exceptional well results**
   Record Beetaloo Basin IP90 test from recent SS-2H ST1 flow test, highlighting rates in-line with core Marcellus Shale ***but the decline profile is considerably different suggesting higher EURs for a comparable IP90***

3. **Large and attractively priced gas markets**
   Opportunity for gas to be sold into the strongly priced domestic market and high growth Asian LNG markets

4. **Partnerships de-risking execution**
   Strategic partnerships with Helmerich & Payne, Liberty Energy and APA Group to provide dedicated, fit-for-purpose equipment, crews and pipeline development. Progressing farmout of ~400,000 acres to de-risk potential significant gas resource to underpin growth strategy

5. **Near-term production**
   Finalizing key stakeholder approvals to deliver initial 40 TJ/d (~39 MMcf/d) (gross) production from the proposed Shenandoah South Pilot Project. Drilling and infrastructure construction underway ahead of first gas in mid-2026

6. **Accomplished operating team supported by experienced Board and management**
   Successful history operating in the Beetaloo Basin supported by an experienced Board and management team who have significant history unlocking large shale plays in the United States

(1) Refer to Australian Government Industry website – "Beetaloo Strategic Basin Plan" (January 1, 2021).

Tamboran's Board of Directors

Deep technical knowledge and track record in early-stage E&P success

Dick Stoneburner
Chairman & Interim CEO

- Over 35 years' experience in petroleum geology
- Former Co-founder, President and COO of Petrohawk Energy Corporation (sold to BHP Billiton Petroleum for US$12.1 billion)
- President North American Shale Production Division at BHP Billiton Petroleum

Scott Sheffield
Director (Non-Executive)

- Over 50 years' experience in the energy industry
- Formerly Director and Chief Executive Officer of Pioneer Natural Resources, which was acquired by ExxonMobil Corporation in 2024
- CEO of Parker and Parsley Petroleum Company, a predecessor company of Pioneer, from 1985 until it merged with MESA, Inc. to form Pioneer in 1997
- Served as a Director of Santos Limited, an Australian E&P company, from 2014 to 2017

Fred Barrett
Director (Non-Executive)

- Co-founder, President, CEO and Chairman of Bill Barrett Corporation
- Previous experience at The Williams Companies, Barrett Resources and Terred Oil

Jeff Bellman
Director (Non-Executive)

- 33-year track record in the investment management industry, with a specific focus on analyzing and investing in the global public oil and gas sector.
- Formerly served as a Managing Director within the equities and fixed income group at Nuveen Investments, a TIAA-CREF Company (Nuveen) for 12 years

Ryan Dalton
Director (Non-Executive)

- Served as Executive Vice President, Chief Financial Officer at Parsley Energy from 2012 until acquired by Pioneer Natural Resources in 2021
- Previously an investment banker in Rothschild's restructuring group as well as a consultant at AlixPartners

Patrick Elliott
Director (Non-Executive)

- Founder of Tamboran Resources in 2009
- Former Director of Eastern Star Gas (sold for A$924 million to Santos) and SAPEX Limited
- Served as Chairman of Meerkat Energy Pty Ltd and Managing Director at Gold Fields Morgan Grenfell

Phillip Pace
Director (Non-Executive)

- Over 30 years of energy industry experience, including credit, equity research and investment banking
- Served as a director of Lonestar Resources US Inc. from 2017 to 2020
- Credit Suisse's Head of Exploration and Production Investment Banking in 2005 and Co-Head of Energy Investment Banking in 2006

Andrew Robb
Director (Non-Executive)

- Member of Australia's House of Representatives for 12 years, including the role of Australia's Minister for Trade, Investment, and Tourism in the Federal Parliament
- Currently Chairman of The Robb Group, Board Member of The Kidman Cattle Enterprise and a range of national and international businesses

David Siegel
Director (Non-Executive)

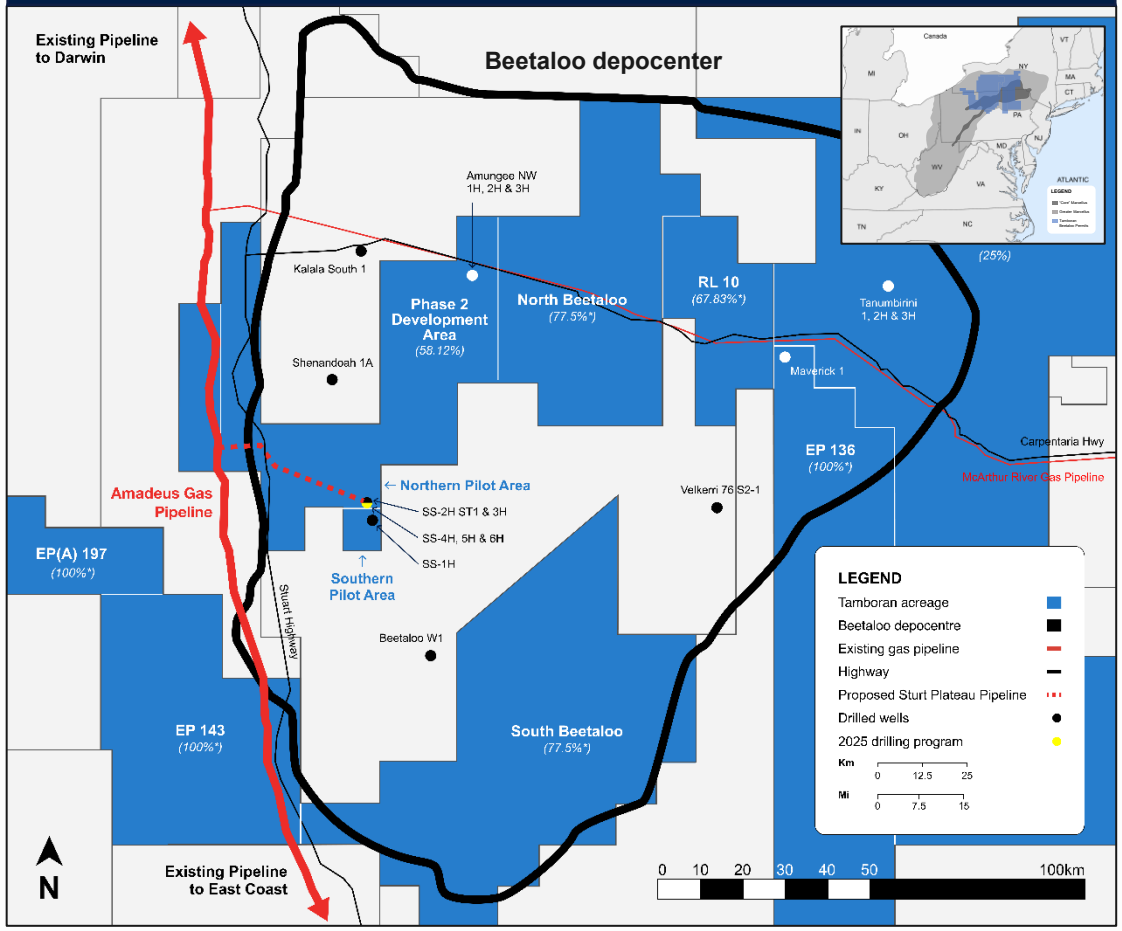
- Formerly Chairman and Managing Member of Longview Petroleum, LLC.
- Serves as a Senior Advisor to Apollo Global Management
- Previously on the Board of member of Trilantic

Tamboran's dominant operated Beetaloo Basin acreage position

Key operator of ~1.9 million net prospective acres in Australia's Beetaloo Basin

Tamboran Resources Corporation (as at close September 10, 2025)	
Stock code:	TBN (NYSE)
Shares on issue (m):	17.8
Share price (US$ per share):	21.96
Market capitalization (US$ million):	**391**
Net debt/(cash) (US$ million)(1):	(90)
Enterprise value (US$ million):	301
Implied acreage value (US$ per acre):	**159**

Tamboran's Beetaloo Basin acreage position ~1.9 million acres (net)



Note: Tamboran operates the Northern Pilot Area, Phase 2 Development Area, North Beetaloo, South Beetaloo, EP 136 and EP 143 acreage.
(1) Cash balance of US$25.6 million at March 31, 2025. Pro forma cash balance of US$90 million post-PIPE and DWE transaction. The closing of the remaining US$11.0 million was approved by Tamboran's shareholders at a Special Meeting of Stockholders on July 16, 2025. The closing of the acreage sale is subject to certain conditions precedent including, and not limited to, DWE obtaining approval from the Formentera Australia Fund, LP's Limited Partner Advisory Committee, Tamboran shareholder approval and regulatory approvals.

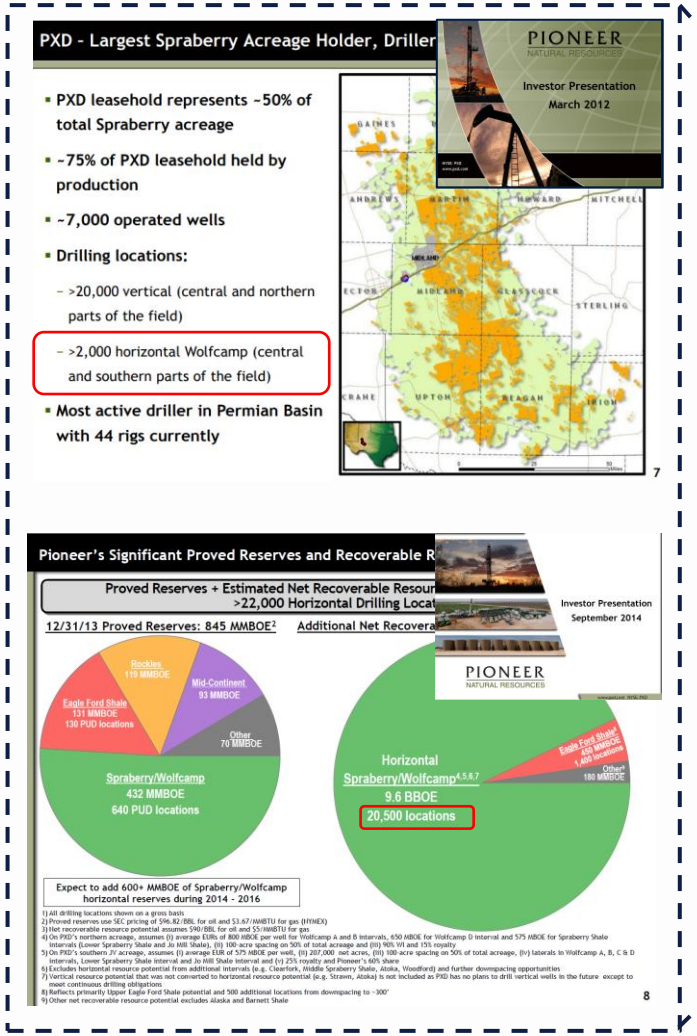
Significant Beetaloo Basin drillable acreage position

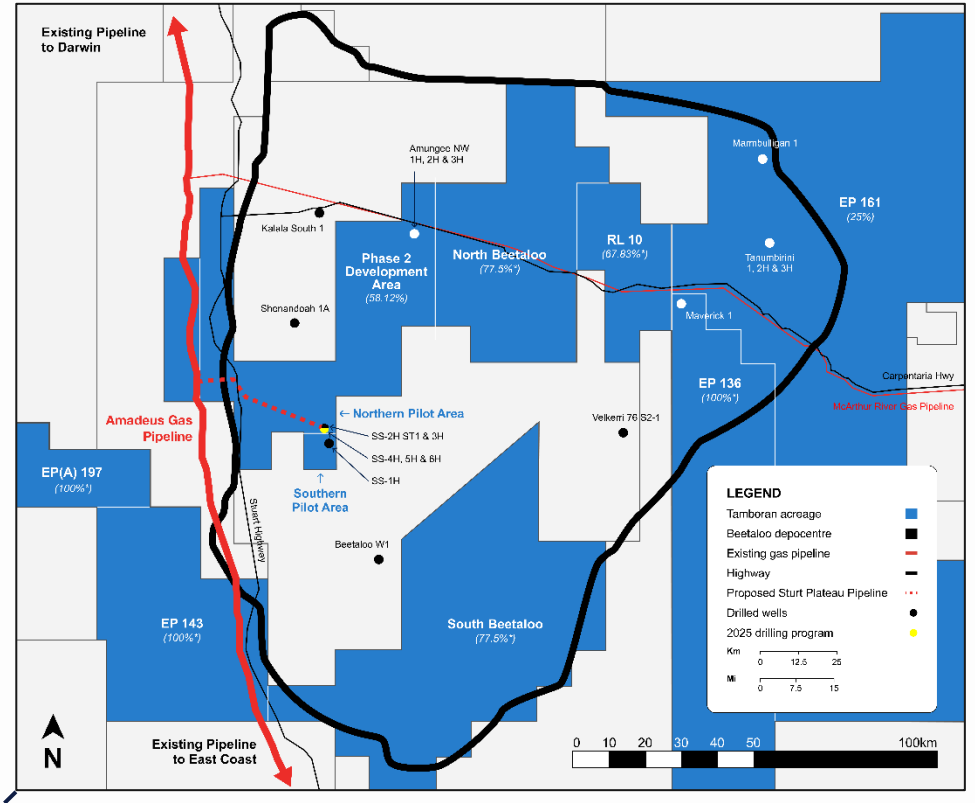
>5,000 drilling locations across a single Beetaloo Basin bench in a stacked shale region with 3 to 4 benches

- The Beetaloo acreage has parallels with Pioneer's Wolfcamp and could offer an opportunity for significant development
- Both plays lend themselves to multi-bench, stacked horizontal development from pads

Potential Locations[(1)]

- **1 Bench: >5,000**
- **2 Bench: >10,000**
- **3 Bench: >16,000**

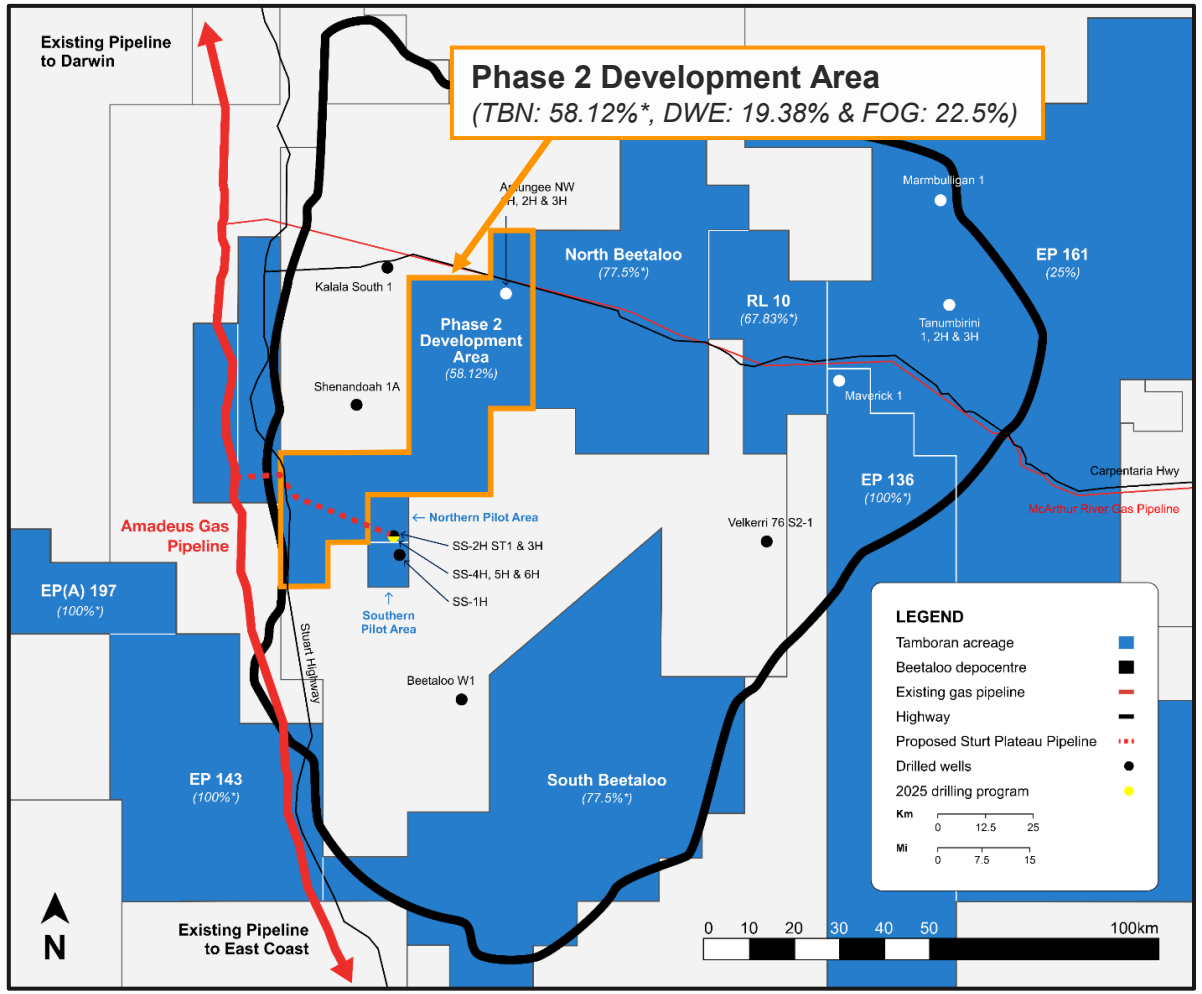




(1) Based on 10,000-foot horizontal wells, with well spacing of ~500 metres.

Tamboran/DWE checkerboard and farmout process

Tamboran progressing towards farmout of ~400,000 acres in Phase 2 Development Area



"Phase 2 Development Area" is the most "development-ready" acreage in the Beetaloo Basin given derisked resources, supportive land access and proximity to existing infrastructure

- 406,693 gross prospective acres (236,370 net operated acres to TBN) in close proximity to derisked Phase 1 Pilot Project and SPP
- Focused development strategy to supply East Coast domestic gas market in stages from 2028-30 to address anticipated ~1 Bcf/d shortfall as highlighted by ACCC(1) and AEMO(2)
- Targeting multiple wells in 2026 to book reserves to support a Phase 2 project sanctioning decision
- **RBC Capital Markets have commenced formal process to farm out Tamboran's working interest in "Phase 2 Development Area"(3)**

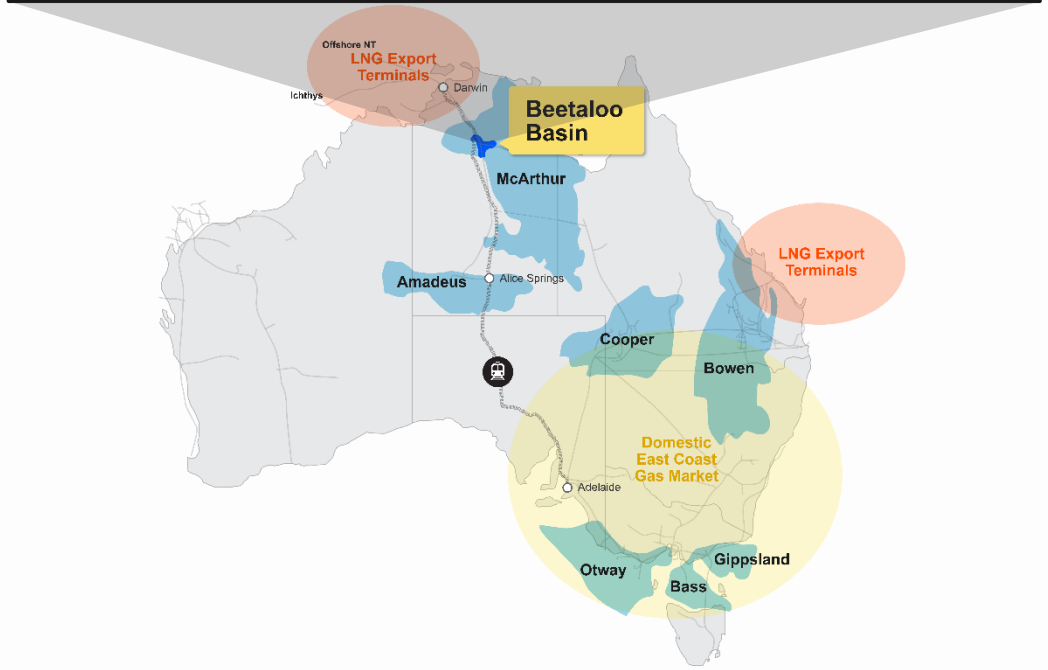
(1) Source: ACCC Gas Inquiry (2017 – 2030): Interim Update on East Coast gas market – June 2025.
(2) Australian Energy Market Operator (AEMO) 2025 Gas Statement of Opportunities (March 2025).
(3) DWE will have participation rights to any transaction on the same terms.

The Beetaloo Basin – One of the largest undeveloped gas resources in the world

Remote location supported by existing pipelines, rail and road infrastructure

- The Beetaloo Basin is located ~300-miles southeast of Darwin in Australia's Northern Territory. Remote flat location, used predominantly by pastoralist leaseholders
- Historically explored by Australian E&Ps (Origin Energy and Santos) with limited shale development expertise and no adoption of US shale technology
- **Existing pipeline infrastructure** with ~100 MMcf/d of capacity and **serviced by a major highway and rail** running from Alice Springs to Darwin
- **Water allocation plan** with available water to support operations
- Potential for **in-field sand mining**
- **Three potential routes to market** via domestic East Coast gas, East Coast LNG export and Northern Territory LNG export
- **Fibre optic network** connecting Darwin to Adelaide via the Beetaloo Basin provides opportunity for Data Center strategy

Shenandoah South 2 well pad in the Northern Pilot Area, Beetaloo Basin



Regional geology provides ideal setting for large, multi-decade Beetaloo Basin development

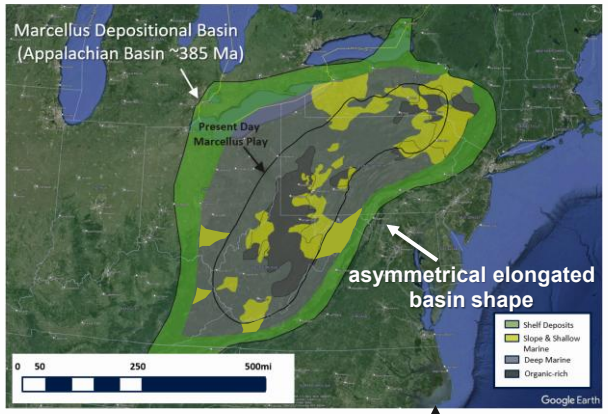
Comparison of Marcellus and Velkerri Shale depositional basins

Marcellus

Appalachian Basin

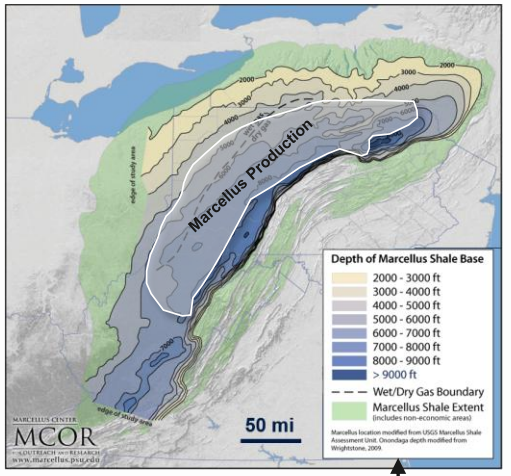
- Foreland basin formed during tectonic collision.
- Produces **asymmetrical elongated basin shape**.
- The present-day Marcellus play area contains basinal sediments that are impacted by the proximity of the basin margin.
- Multiple rock types—deep marine **organic rich shale**, deep marine **organically lean shale**, slope & shallow marine **carbonates**, slope & shallow marine **siltstones**.

Lithology Distribution



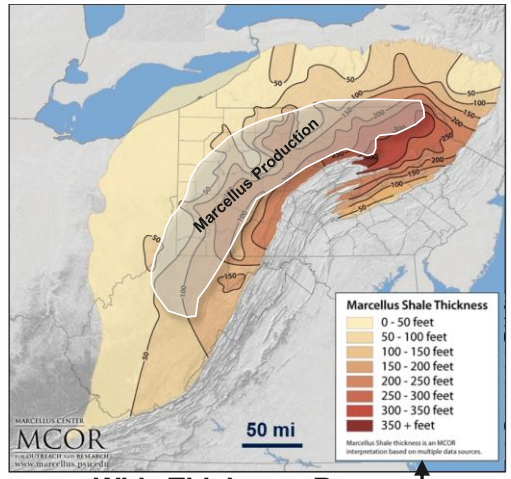
Multiple Rock Types

Depth



Wide Range of Depths
(5,000 – 9,000 ft)

Thickness



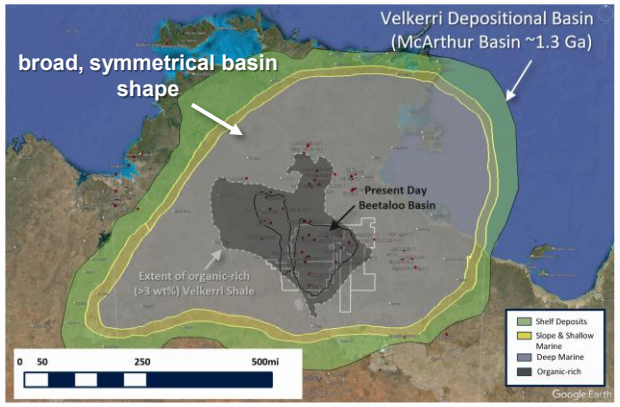
Wide Thickness Range
(50 – 350 ft)

Beetaloo

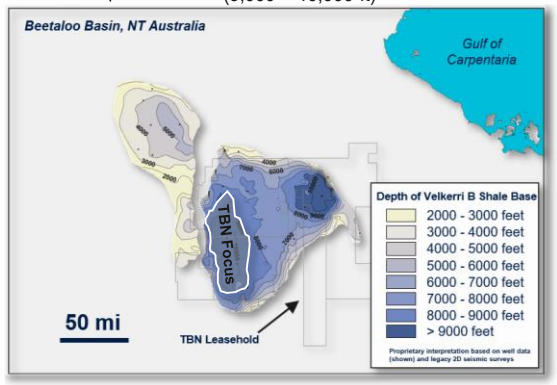
Beetaloo Basin

- Inter-cratonic basin formed after tectonic rifting.
- Produces **large, broad, symmetrical basin shape**.
- The present-day Beetaloo Basin contains the McArthur Basin's most distal, basinal sediments.
- Singular rock type—deep marine **organic rich shale**.

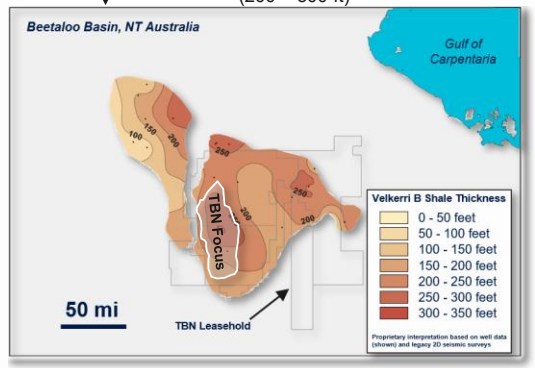
Single Rock Type



Narrow Range of Depths
(9,000 – 10,000 ft)



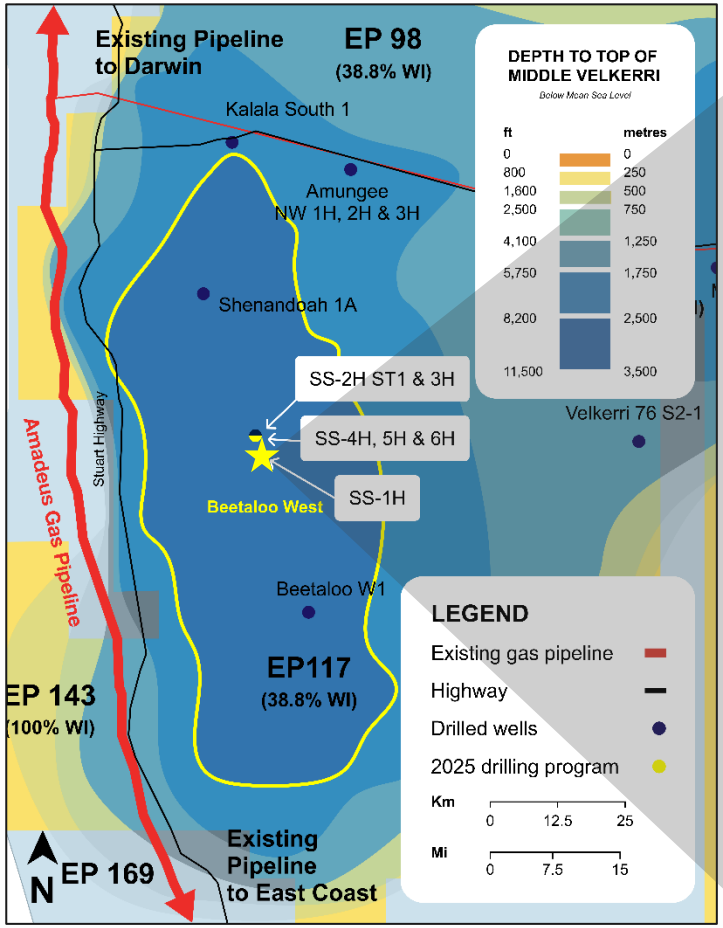
Narrow Thickness Range
(200 – 300 ft)

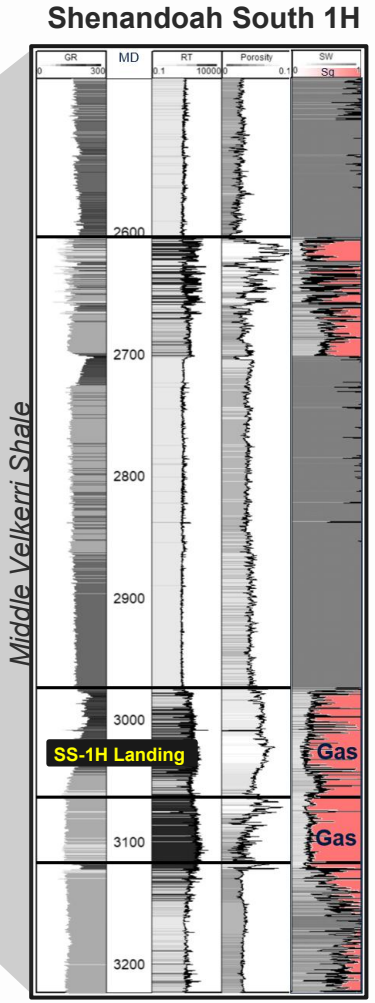


Source: Marcellus Facies Distributions from Wang, G. and Carr, T. (2013), AAPG Bulletin, v. 97, No. 12, pp. 2173-2205.

Shenandoah South 1H drilled in deepest section of Mid-Velkerri gas play in the Beetaloo West area

Geological rock properties at SS-1H compare favorably with those in the average Marcellus Shale dry gas window



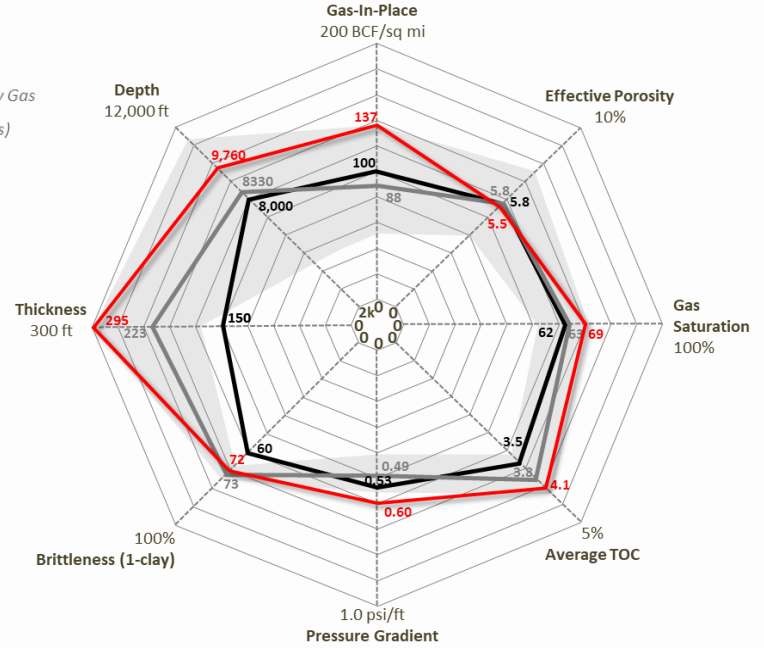


- SS-1H well logged ~480 ft of high quality, stacked Middle Velkerri shale interval at ~10,000-foot depth
- Reservoir properties of Mid-Velkerri 'B' and 'Lower B' shale compares favorably to the average Marcellus Shale dry gas window
- Reservoir pressure gradient up to ~0.6 psi/ft observed
- **SS-1H drilled 1,000 metre (3,281 ft) horizontal and stimulated ~500 metres (1,640 ft) in highest quality section of Mid Velkerri B shale** in the Beetaloo Basin to date

Average Marcellus Shale Tier 1 Dry Gas
Average Velkerri B Dry Gas (8 wells)
Shenandoah S1 Velkerri B Dry Gas
Velkerri B Data Range (8 wells)

Primary 'B' Shale (~300 ft)

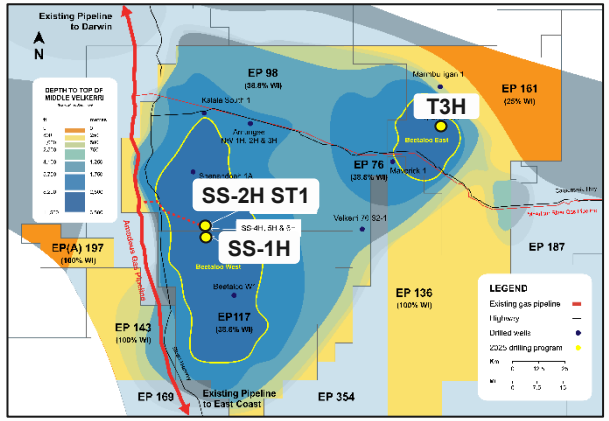
Secondary 'Lower B' Shale (~180 ft)

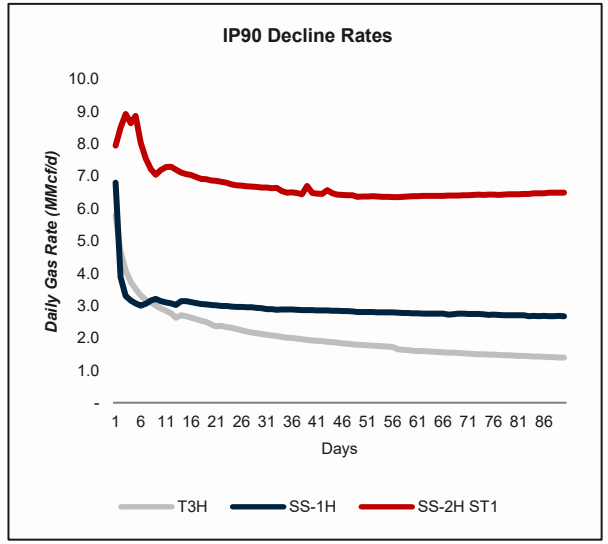


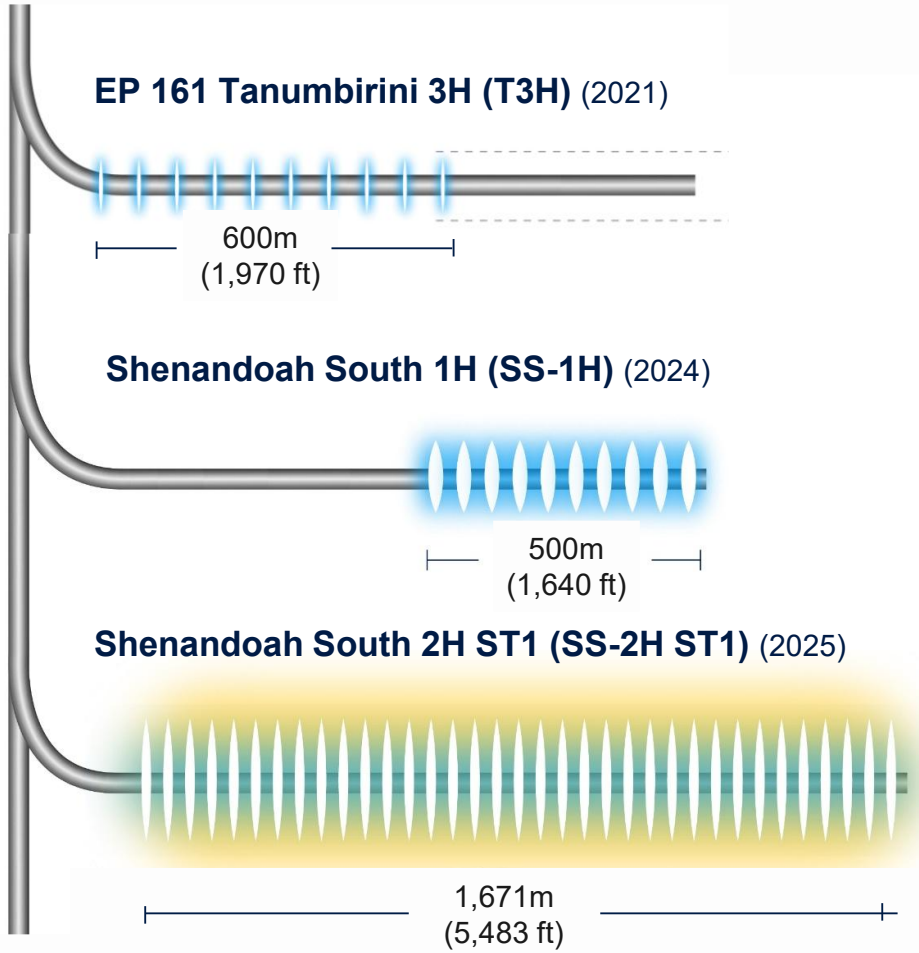
Source: Based on core data from Tanumbirini 1, Amungee NW1, Kalala S1, Beetaloo W1 and Maverick 1. Proprietary core-calibrated modelling performed by Nutech (2023). Marcellus shale Tier 1 Dry Gas Area average reservoir properties from Enverus Foundations™ Geoscience Analytics (2023).
Pressure gradient estimation for SS-1H is based on a linear flow analysis of the Diagnostic Fracture Injection Test (DFIT) and build-up analysis during flowback of the SS-1H.

Application of optimized "US-style" completion design for SS-2H ST1

Incorporating lessons from SS-1H and SS-2H ST1 to further improve well performance and cost efficiency in SS-3H/4H/5H/6H







Santos Design (4-½" casing, 1,600 lbs/ft, 60 bpm)

10 stimulation stages over ~1,970 ft (600 m)

IP90 flow test delivered 2.1 MMcf/d

Application of T3H Learnings

Tamboran v1 Design (5-½" casing, 2,210 lbs/ft, 90 bpm)

10 stimulation stages over ~1,640 ft (500 m)

IP90 flow test delivered 2.9 MMcf/d

Application of SS-1H Learnings

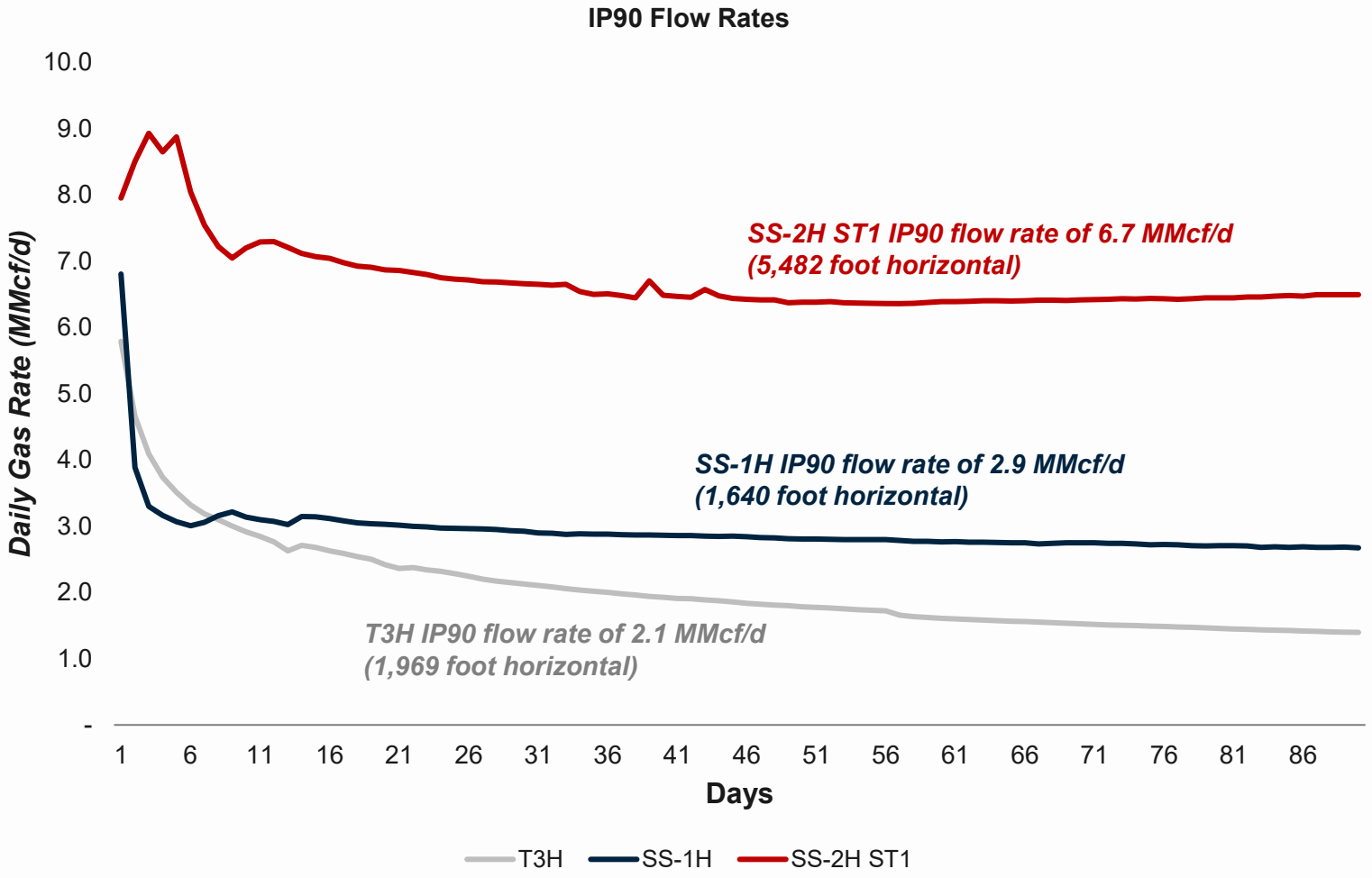
Tamboran v2 Design (5-½" casing, 2,710 lbs/ft, 95 bpm)

35 stimulation stages over ~5,483 ft (1,671 m)

IP90 flow test delivered 6.7 MMcf/d

Shenandoah South 2H ST1 IP90 flow test results

Record Beetaloo Basin IP90 test of 6.7 MMcf/d[(1)] | Increasing lateral length delivering higher flow rates

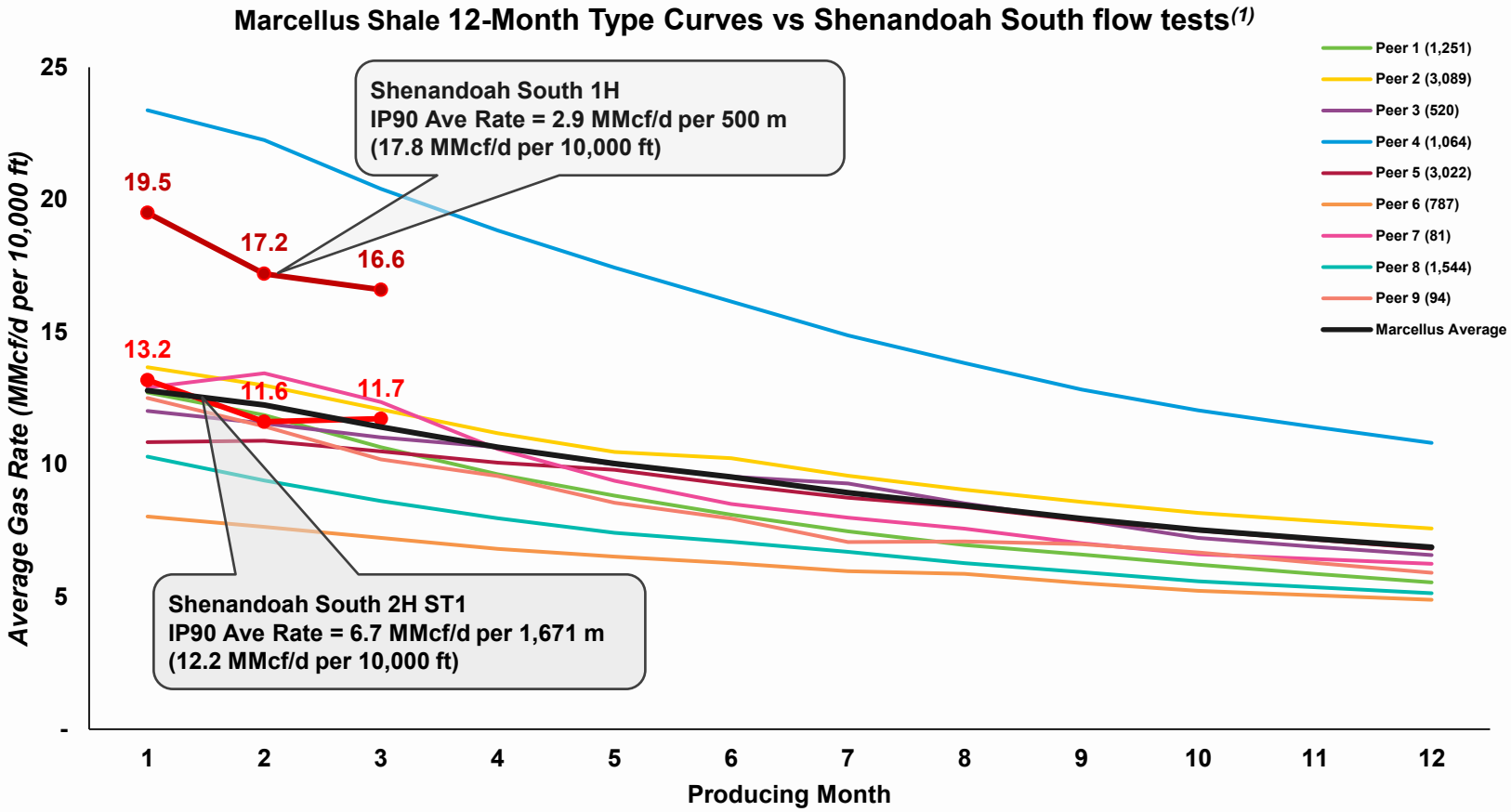


- **Record Beetaloo Basin IP90 flow rate of 6.7 MMcf/d[(1)]**
- 2% increase in flow rate during final 30 days, which may indicate significant matrix contribution and/or enhanced fracture conductivity
- Flowing tubing pressure remaining stable at ~700 psi on a 44/64” choke
- Performed less aggressive choke schedule (vs. SS-1H) to protect early flow back fracture connectivity and maintain higher flowing wellhead pressure
- Well shut-in ahead of commencement of sales to Northern Territory Government in mid-2026, subject to weather and securing customary stakeholder approvals

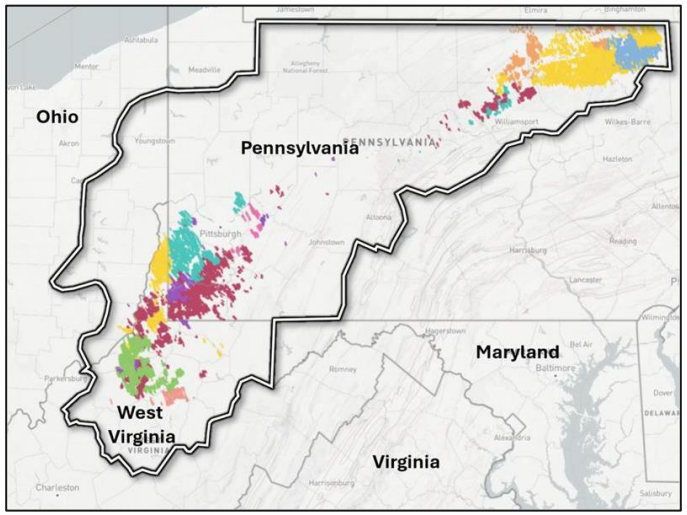
(1) Refer to Announcement (August 11, 2025): “SS-2H ST1 record IP90 flow test”.

Shenandoah South 2H ST1 IP90 performance vs. Marcellus Shale producers

SS-2H ST1 IP90 result in-line with average of >11,000 Marcellus Shale wells produced for over 12 months



Marcellus, Appalachian Basin (US)

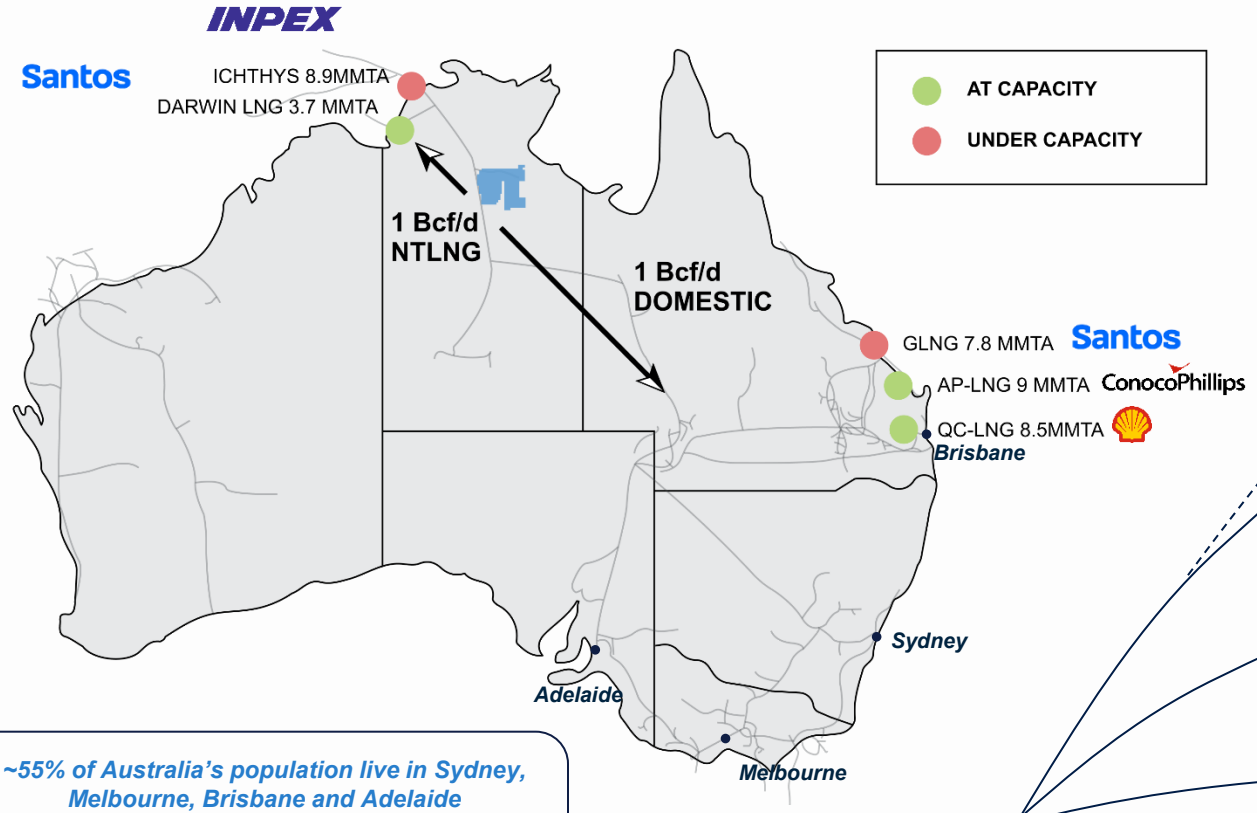


- The IP90 of the Mid Velkerri B Shale at SS-2H ST1 compares favourably with average rates from >11,000 Marcellus Shale producers
- Decline profile is considerably different suggesting higher EURs for a comparable IP90

(1) SS-1H initial 90-day and SS-2H initial 90-day production plotted against average of wells within the Marcellus shale, grouped by operator, normalized to 10,000 ft lateral length. First SS-1H initial 90-day and SS-2H initial 90-day production plotted against average of wells within the Marcellus shale, grouped by operator, normalized to 10,000 ft lateral length. First month production for Marcellus based on first full calendar month of production; SS-1H and SS-2H ST1 wells commenced testing following a "soaking" period of three weeks and ~60 days respectively. SS-1H average 90-day gas rate of 2.9 MMcf/d for 500-metres (~1,640 ft) stimulated lateral length normalized to 10,000 ft, shown in red. SS-2H ST1 average 90-day gas rate of 6.7 MMcf/d for 1,671-metres (~5,483 ft) stimulated lateral length normalized to 10,000 ft, shown. Marcellus comparison includes 11,452 wells with minimum 12 months of production from the following operators: Antero Resources, Expand, CNX Resources, Coterra Energy, EQT, HG Energy, Olympus Energy, Range Resources, and Repsol. Marcellus Production Data Source: Enverus Prism Foundations™ Forecast Analytics (Data accessed June 12, 2025).

Market access and proposed development strategy

Aspiration to grow gross production to 2 Bcf/d by early 2030s[1] | Exploring additional markets via LNG backfill and Data Centers



~55% of Australia's population live in Sydney, Melbourne, Brisbane and Adelaide

~87% of Australia's population live in the East Coast and southeastern states

Multiple upside opportunities
Assessing opportunities for LNG backfill, NTLNG expansion and Data Centers

2 Bcf/d (*gross*)

Phase 3 – NTLNG (early 2030s)
1 Bcf/d via new pipeline to NTLNG (~6 MTPA)

1 Bcf/d (*gross*)

Phase 2 – Domestic Market (2029-30)
1 Bcf/d via new pipeline to Australian East Coast market

40 TJ/d (~39 MMcf/d) (*~19 TJ/d net TBN*)[2],[3]

Phase 1 – Pilot Development (2026)
~40 MMcf/d via existing Amadeus Gas Pipeline to NT gas market

2026 2028 2030 2035

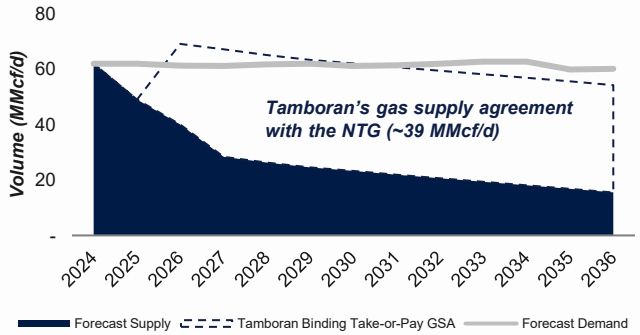
(1) Reflects gross Beetaloo Basin production aspirations by 2030 from assets (Tamboran has ownership in Northern Pilot Area, Phase 2 Development Area, North Beetaloo, South Beetaloo, EP 136, 161 and EP 143 acreage).
(2) Subject to available pipeline capacity in the Amadeus Gas Pipeline and Blacktip production by 2026.
(3) TBN expects to hold >48.5% Working Interest in the Northern Pilot Area. Final working interest to be settled following the successful stimulation of the SS-3H and SS-4H wells.
Note: Timings for phased development are flexible and subject to commercialisation of Beetaloo gas resources and key stakeholder and JV approvals.

Favorable macro-outlook for Beetaloo Basin development

Emerging shortfalls within the NT, East Coast and international LNG gas markets supporting Tamboran's Beetaloo growth strategy

Local NT gas

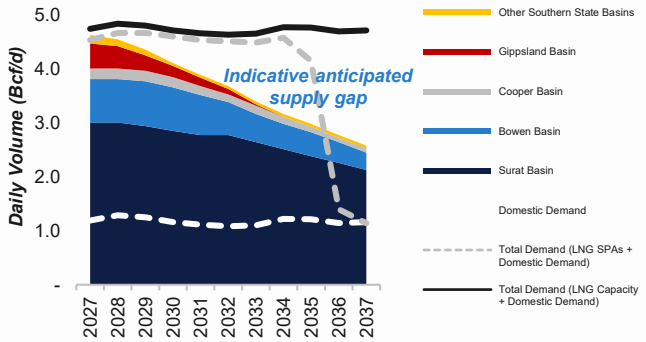
AEMO Northern Territory Supply/Demand Forecast(1)



- Gas is the primary source of electricity generation for the NT
- Total market demand of 60 – 70 MMcf/d in the NT, plus 90 MMcf/d to the East Coast via the Northern Gas Pipeline
- Primary source of gas for the NT is in terminal decline
- TBN has a take-or pay GSA for 40 TJ per day from the proposed SS Pilot Project until mid-2041 with first gas planned for mid-2026

East Coast gas

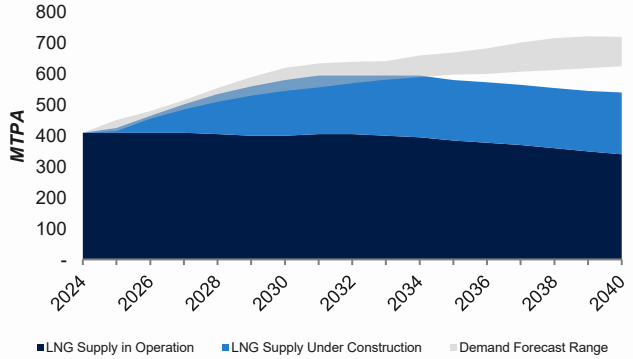
Forecast East Coast supply-demand outlook(2)



- Domestic supply expected to decline in coming years leading to anticipated domestic shortfall
- Near-term opportunity to fill ullage in GLNG (~0.3 MMcf/d)
- Medium-term opportunity for backfill of QCLNG and APLNG coal seam feed gas
- >1 Bcf/d of shortfall anticipated on the East Coast from early 2030s(2)

International LNG

Global LNG Supply/Demand Forecast3



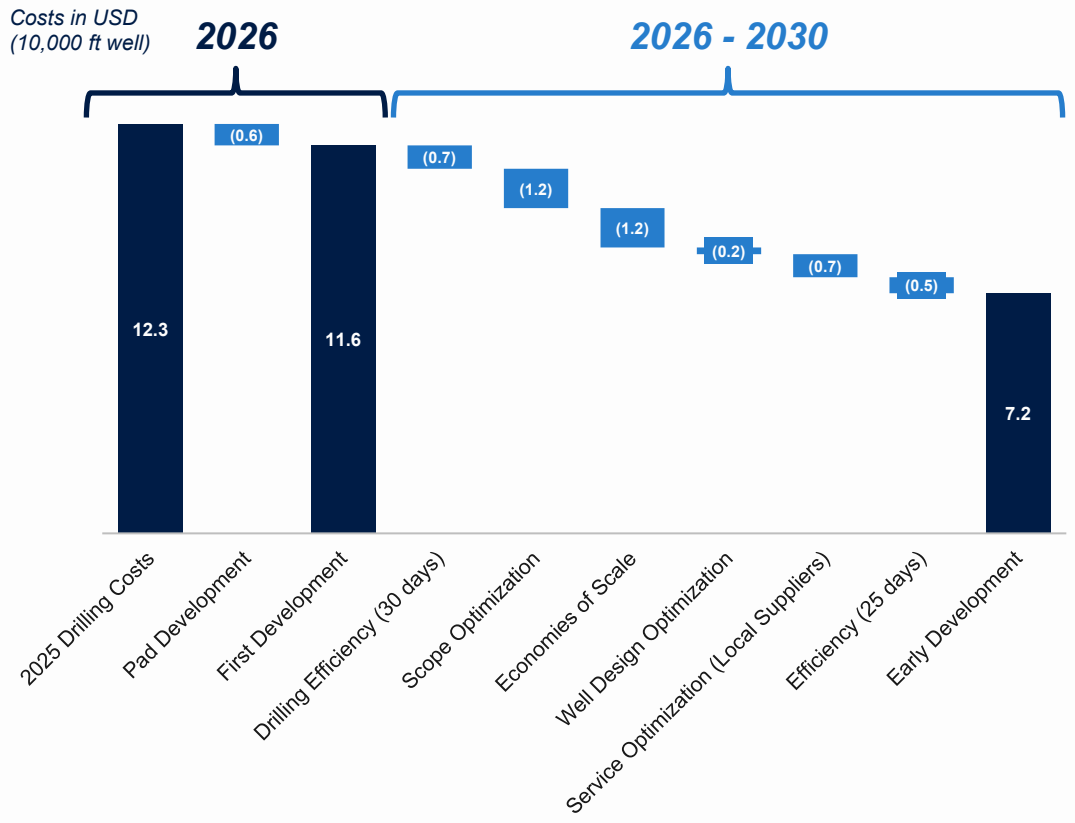
- Global LNG market could be >30 MTPA short by 2030 due to
  - Demand for natural gas as transition from coal
  - Demand for natural gas in the transportation sector
  - Demand from growing middle class in Asia and AI Data Centers
  - Diminished Russian LNG exports

(1) Source: Australian Energy Market Operator (AEMO) 2024 Gas Statement of Opportunities (March 20, 2025), p.80.
(2) Source: Source: ACCC Gas Inquiry (2017 – 2030): Interim Update on East Coast gas market – June 2025 (p.45). ACCC analysis of data obtained from gas producers as at January 2025 and domestic demand from AEMO's March 2025 GSOO.
(3) Source: Shell LNG Outlook 2025 (February 2025), slide 26. Cased on Shell's interpretation of Wood Mackenzie, S&P Global Commodity Insights, Poten & Partners, Rystad Energy and FGE data.

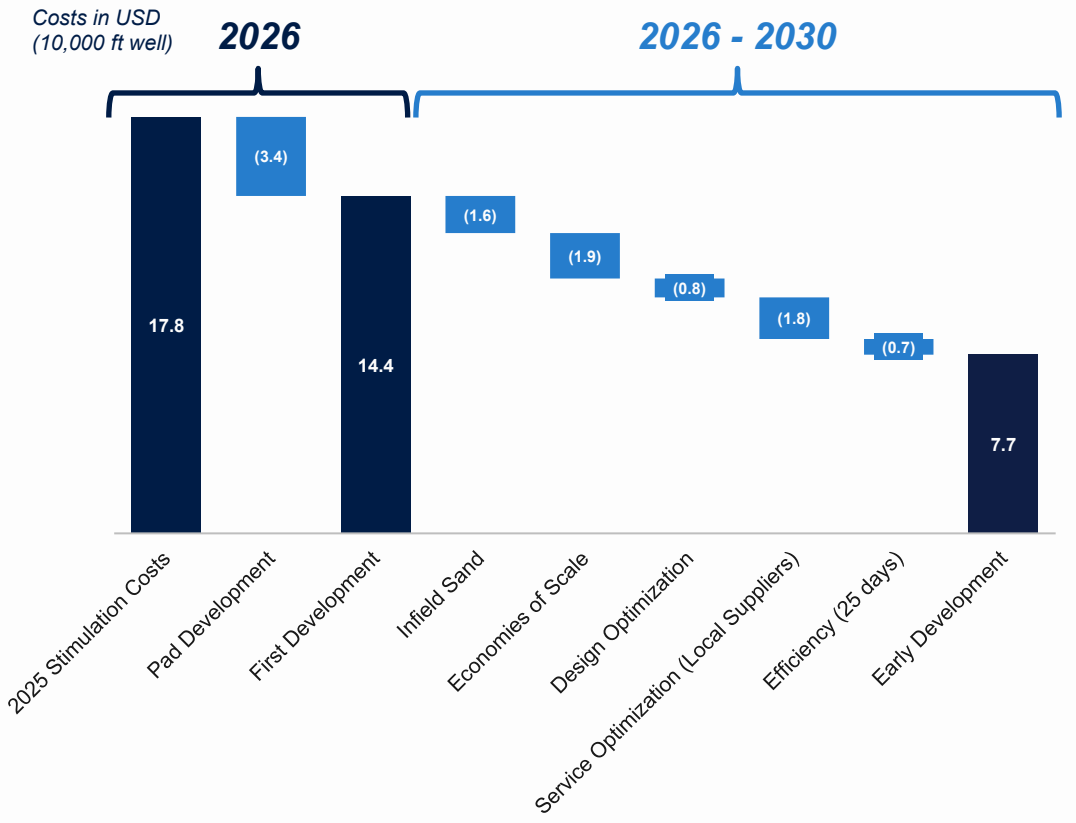
Robust plans towards cost reduction

Targeting ~50% reduction and drilling & completion costs with progression to continuous operations

Targeted savings throughout drilling program



Targeted savings throughout stimulation program



Savings driven by continuous operations, build-out of local service providers, local sand solution and operational efficiencies

Tamboran's Strategic Partnerships in place to accelerate large scale Beetaloo and LNG development

Delivering on commitment to import US technology and build additional pipelines into the Beetaloo Basin

(*5.7% TBN shareholder*)

Strategic Drilling Partner

- Tamboran / H&P (NYSE: HP) Strategic Alliance to import modern US unconventional drilling rigs into the Beetaloo Basin (**currently operating**)
- Two-year rig contract in place for initial H&P FlexRig® super-spec rig and an **option to import four additional FlexRig super spec rigs into the Beetaloo Basin**
- **Commenced three well drilling program in July 2025**

(*5.3% TBN shareholder*)

Strategic Completions Partner

- Tamboran and Liberty (NYSE: LBRT) entered into Strategic Partnership to import a modern frac fleet into the Beetaloo Basin in 2024
- Fit-for-purpose completion equipment has **potential to significantly reduce costs of future completions** and increase efficiency
- **Successfully completed 35 stage stimulation program** within the SS-2H ST1 well. SS-4H stimulation planned for 2H 2025

Strategic Pipeline Partner

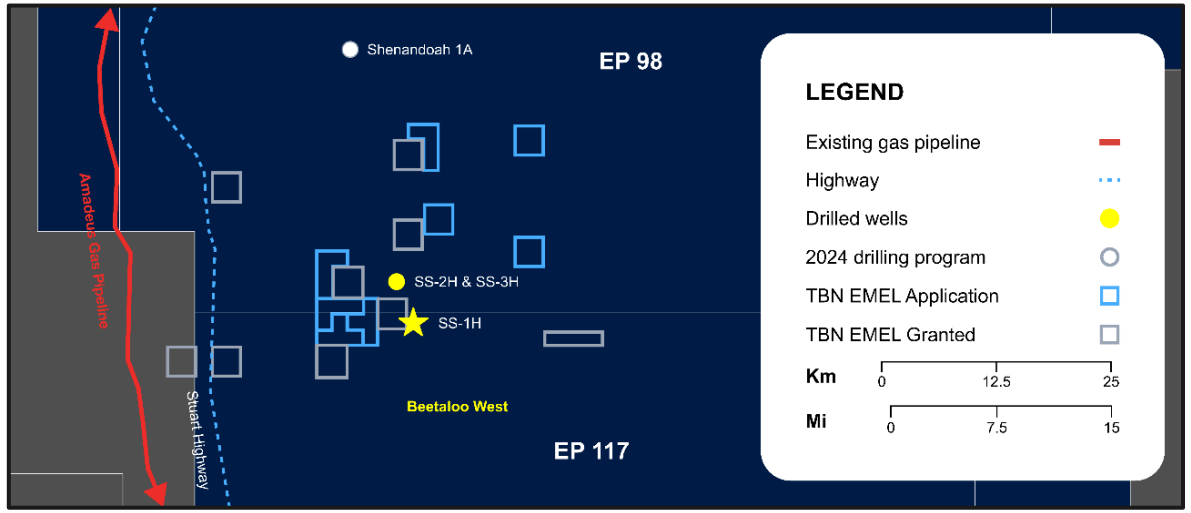
- Tamboran and APA Group (ASX: APA) entered into **three binding agreements to support the development of the Beetaloo Basin** assets to the East Coast gas market and Darwin
- Reached final binding agreements with APA to deliver the Sturt Plateau Pipeline (SPP), which connects the Pilot Project with the Northern Territory market
- APA to build, own and operate the 12-inch, 23-mile pipeline

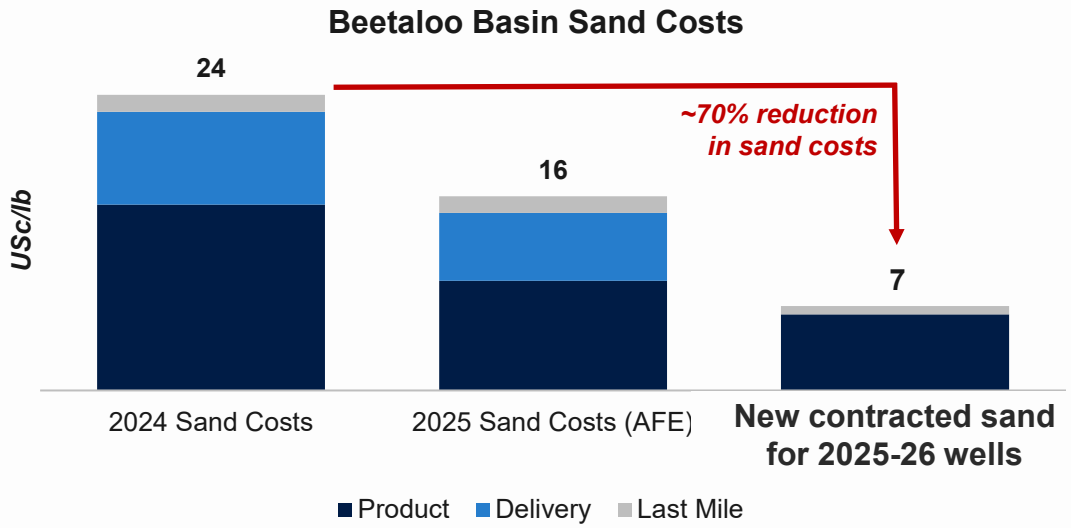
LNG Pre-FEED EPC Contractor

- Awarded Pre-FEED contract to Bechtel, one of the world's most experienced LNG EPC contractors
- **NTLNG pre-FEED completed** in mid-2025
- Tamboran to explore partnership opportunities to proceed with additional work, including commencement of FEED activities (potentially via the farmout process)

Northern Territory local sand secured for SS-3H, 4H, 5H and 6H completions

Ongoing discussions with potential third-party strategic partners to develop first Beetaloo Basin local sand mine in 2026





- Tamboran has secured sand from NT local supplier for the 2025-26 stimulation program at ~US$0.07/lb (~70% lower than 2024 imported sand costs)
- Local sand will be delivered in bulk which will improve efficiencies and remove waste associated with imported bagged sand
- **Ongoing discussions with potential strategic partners to develop first Beetaloo Basin local sand mine in 2026, which is expected to further reduce sand cost to <US$0.05/lb**

Upcoming catalysts

Progressing towards production from proposed 40 TJ/d (~39 MMcf/d) SS Pilot Project in mid-2026

2H 2025	Commence RBC farmout process for Phase 2 Development Area
2H 2025	Drilling of SS-4H/5H/6H Pilot development wells
2H 2025	Target Final Investment Decision of the proposed SS Pilot Project
2H 2025	Commence construction of SPCF compressor and SPP pipeline
2H 2025 / 1Q 2026	Stimulation and IP30 flow test of SS-4H
1Q 2026	Finalize farmout of Phase 2 Development Area
1H 2026	Stimulation 4H, 5H and 6H wells ahead of commencement of production
Mid 2026	Target SS Pilot Project first gas sales of 40 TJ/d

Note: Timing of upcoming catalysts is indicative, and subject to change in the event of unforeseen events, delays due to weather and key stakeholder and Joint Venture approvals. Refer to disclaimer on Slide 2.

Investment highlights

Significant gas development in the Beetaloo Basin, with potential to become a world class gas province[1]

1. **Significant unconventional gas resource**
2. **Exceptional well results**
3. **Large and attractively priced gas markets**
4. **Partnerships de-risking execution**
5. **Near-term production**
6. **Accomplished operating team supported by experienced Board and management**

(1) Refer to Australian Government Industry website – "Beetaloo Strategic Basin Plan" (January 1, 2021).

Appendix

Phase 1 – Proposed Shenandoah South Pilot Project

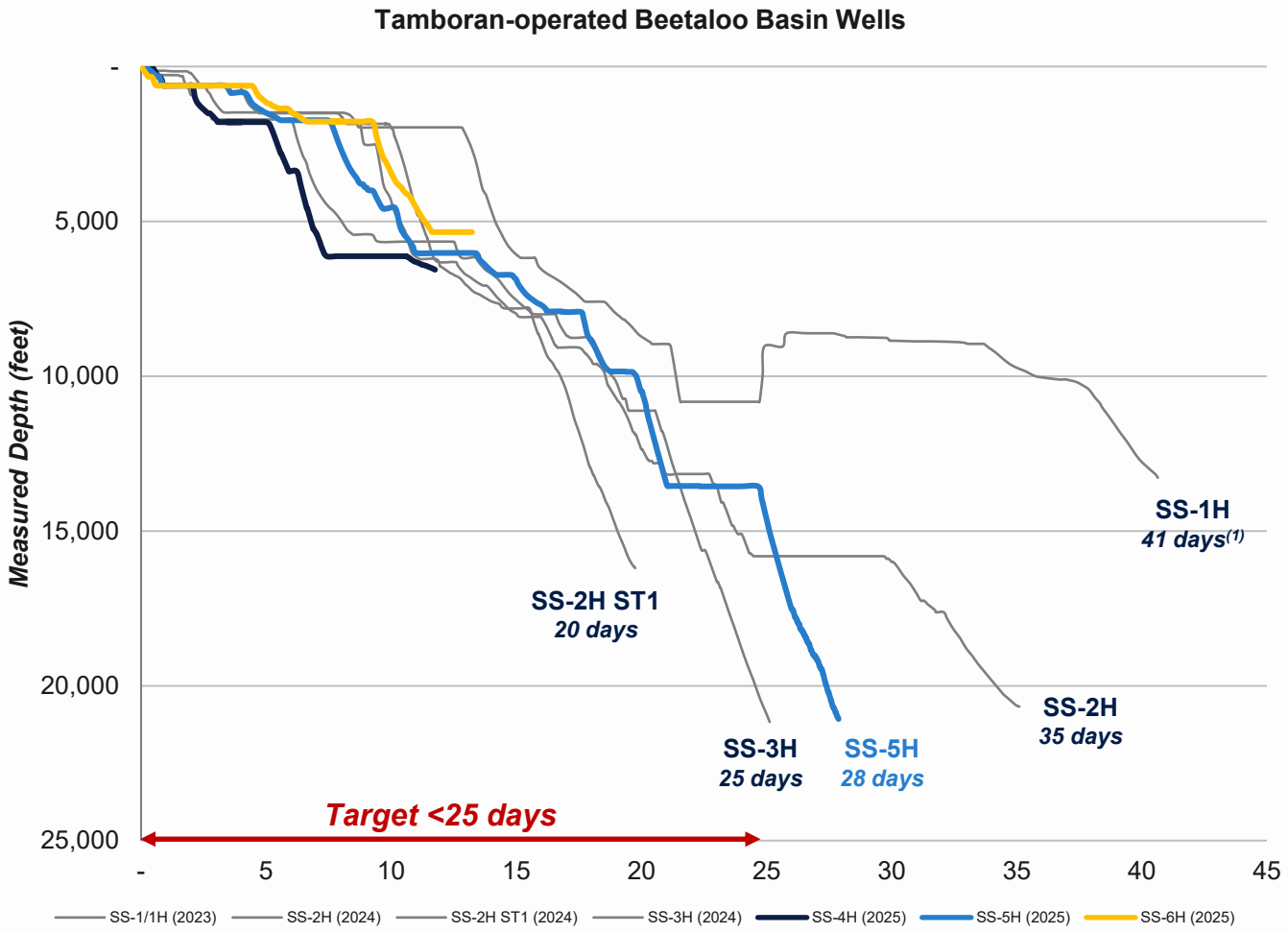
Initial phase to deliver 40 TJ/d (~39 MMcf/d) and expansion capability to ~100 TJ/d (~98 MMcf/d) via existing infrastructure

- Targeting delivery of gas into the local Northern Territory gas market from mid-2026, subject to weather and remaining customary stakeholder approvals
- Pilot development is designed to utilize the existing Northern Territory pipeline network to allow early production of appraisal wells
- Ability to achieve longer term decline profile without the impact of flaring whilst accelerating royalties to the Northern Territory Government and Native Title Holders
- Initial 40 TJ/d fully contracted to the Northern Territory Government until mid-2041 under CPI-linked gas contract(1)
- Drilling of remaining three wells underway to deliver the 40 TJ/d (~39 MMcf/d) plateau (initially from five wells)
- Construction of the SPCF ~54% complete
- Expansion of SPCF available by as early as 2028 for up to 100 TJ/d (~98 MMcf/d) using existing pipeline infrastructure(2)
- Tamboran to hold >48.5% average ownership across the initial five wells following the successful stimulation program

(1) Initial 9-year term with buyer's option to extend the GSA to mid-2041.
(2) Subject to available capacity within existing pipeline network.

Phase 1 – SS Pilot Project drilling in 2H 2025 to focus on driving further reduction in cost

Successfully drilled SS-5H with 10,000-foot horizontal section | Currently drilling SS-4H horizontal section



- Batch drilling of three wells (Tamboran 50% operator, DWE 50%) commenced in July 2025
  - Targeting ~21,000-foot measured depth well, including 10,000-foot horizontal section
  - Successfully drilled SS-5H with 10,000-foot horizontal section
  - Currently drilling SS-4H horizontal section
- Comprehensive review of SS-2H ST1 and SS-3H drilling performance identified opportunities for further efficiencies and cost reductions, including;
  - Batch drilling of top-hole sections
  - Optimized bit design and directional tools with advanced anti-vibration technology for improved horizontal drilling performance
  - Improved systems to limit Non-Productive Time (NPT)

Targeting spud-to-TD timing of <25 days for SS-4H, 5H and 6H wells

(1) SS-1H well drilled to TD in 41 days (34.7 days to drill to horizontal section TD without pilot hole activities). Reached TD on vertical pilot hole in 21.5 days. The vertical section added 6.3 days to overall drilling of SS-1H.

Phase 1 – Upstream operational update

Initial five wells on track for stimulation by mid-2026 ahead of first gas sales to the Northern Territory Government

H&P Flex 3 Rig undertaking the 2025 drilling program

SS-2H ST1

- Successfully completed stimulation of SS-2H ST1 across 35 stages over a 5,483-foot (1,671-metre) horizontal section in the Mid Velkerri B Shale, reaching Beetaloo Basin records for average proppant intensity
- Flow tested over 90-days, delivering record Beetaloo Basin average IP90 rate of 6.7 MMcf/d(1)

SS-3H

- First well drilled with 10,000 feet horizontal section in the Beetaloo Basin
- Successfully remediated stressed casing connection with extended pressure testing demonstrating well integrity
- Well suspended ahead of stimulation in 1H 2026 campaign

SS-4H, -5H and -6H

- SS-5H successfully drilled with 10,000-foot lateral section. Currently drilling the SS-4H horizontal section
- SS-4H well to be stimulated during 4Q 2025 ahead of IP30 test in 1Q 2026
- SS-5H and -6H to be stimulated in Q2 2026 campaign
- Target average well cost of US$30 million(2)

(1) Refer to ASX Announcement (August 11, 2025): "SS-2H ST1 record IP90 flow test".
(2) Well costs include drilling (US$12 million) and stimulation (US$16 million) and extended production testing (US$2 million). Excludes pad development, Native Title payments, etc.

Phase 1 – Sturt Plateau Compression Facility (SPCF)

Dehydration and compression of gas ahead of sale to the NTG | Targeting completion in mid-2026

- Raw gas is lean (~92% methane) and requires dehydration and compression of gas stream prior to injection in the transmission pipeline
- **Owner:** SPCF sub-trust (SPCF Pty Ltd)
- **Ownership structure:** 50% Tamboran, 50% Daly Waters Energy, LP
- **P50 cost:** US$90 million (~US$45 million net Tamboran)
- **Funding:** ~US$20 million (gross) spent to date, nearing completion of financing facility to fund remaining ~US$70 – 80 million
- **Capacity:** 50 TJ/d (~49 MMcf/d) with expansion opportunity to increase to 100 TJ/d (~98 MMcf/d)(1)
- SPCF sub-trust to charge an expected indicative tariff of ~US$2.5 million per month(2) to upstream operations to process gas before delivering into the APA-operated Sturt Plateau Pipeline (SPP)
- Opportunity to sell SPCF facility to a third-party post-commissioning to unlock equity cash for upstream activities
- The project is currently ~54% complete, and below the budget estimate
- On track for completion in mid-2026

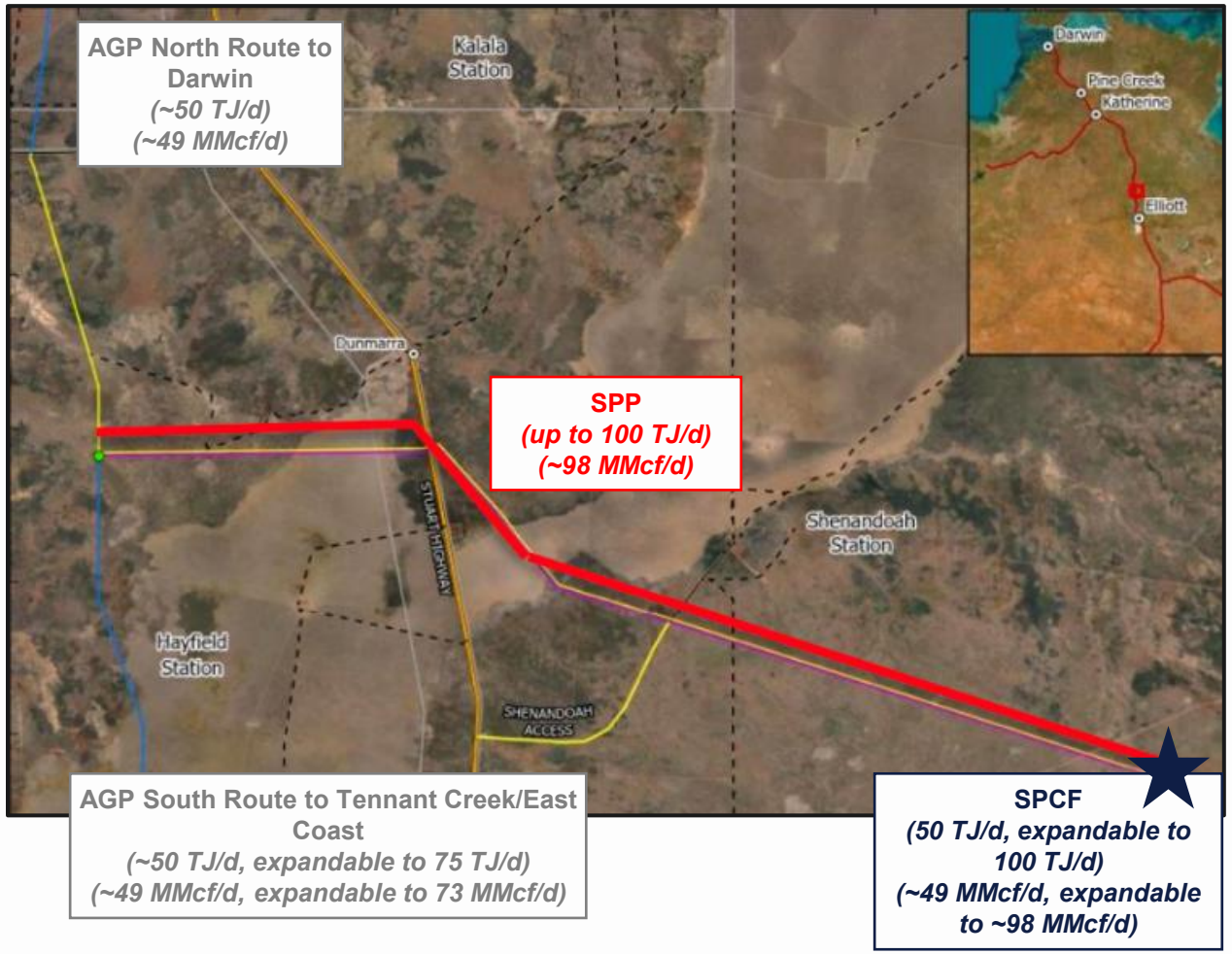
SPCF compressor arriving at SS2 pad site (September 2025)

(1) Expansion to 100 TJ/d for P50 Class 4 estimate of ~US$50 million (gross). Available to commence expansion production ~2-years following FID. Subject to pipeline availability.
(2) Indicative monthly tariff to be finalized based on the total cost of delivering construction of the SPCF and the SPP.

Phase 1 – Sturt Plateau Pipeline (SPP)

Pipeline designed to deliver gas to the local Northern Territory market | On track for completion in mid-2026

- ~23-mile, 12” gas pipeline owned and operated by APA Group (ASX: APA)
- Planned to connect the SPCF to the APA-owned AGP (running from Darwin in the north to Alice Springs in the south)
- Access to the AGP is the sales point for gas to the Northern Territory Government
- Design capacity of 50 TJ/d (~49 MMcf/d), with an expanded capacity up to 100 TJ/d (~98 MMcf/d)
- Tamboran and DWE have contracted all foundational capacity on the SPP from the commencement of operations until at least 2041
- Tamboran and APA are close to finalizing Gas Transportation Agreements
- Construction planned to commence in mid-September 2025
- Total pipeline cost of ~US$40 million resulting in an expected indicative tariff of ~US$0.5 million per month(1) (escalated at CPI)

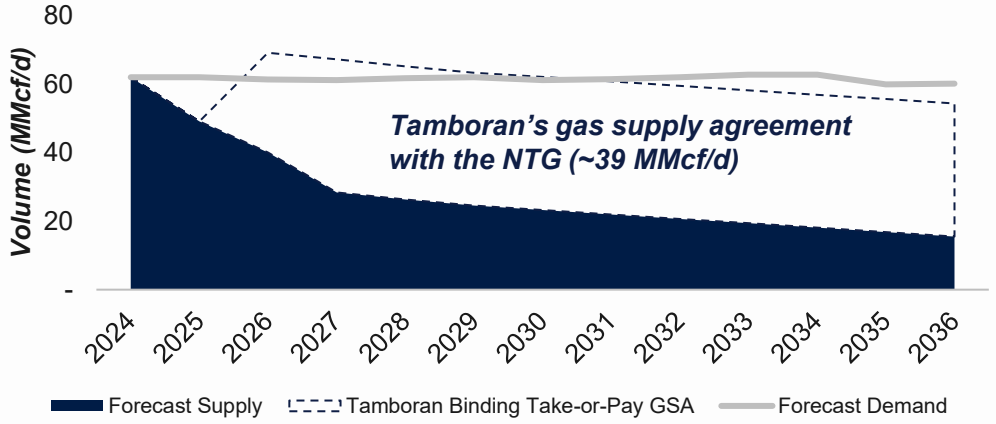


(1) Monthly tariff to be finalized based on the total cost of delivering construction of the SPP.

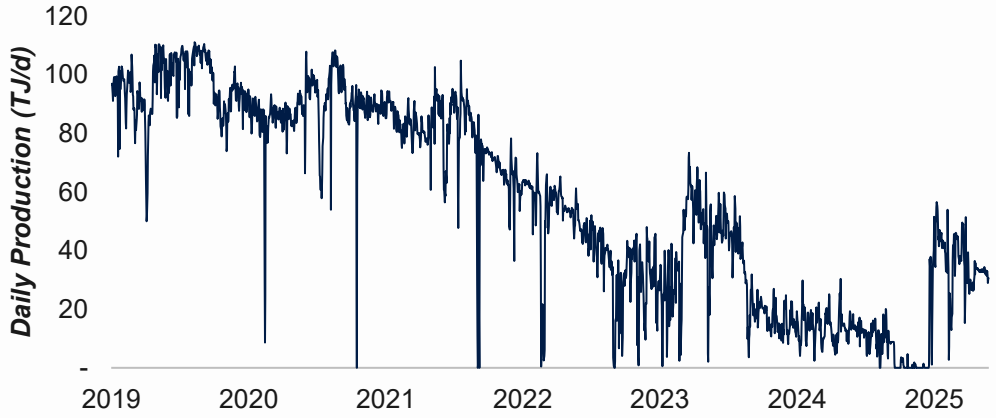
Phase 1 – Northern Territory gas market dynamics

Immediate opportunity to meet gas demand for the local market delivering energy security to Territorians

AEMO Northern Territory Supply/Demand Forecast(1)



Gas flows from Blacktip(2)



- Gas is the primary source of electricity generation for the Northern Territory
- **Total market demand:** 60 – 70 MMcf/d in the NT, plus pipeline capacity to export a further 90 MMcf/d to the East Coast via the Northern Gas Pipeline
- Blacktip (operated by Eni Spa) has been primary source of gas for the Northern Territory, currently in terminal decline
- NTG introduced legislation to allow for the beneficial use of gas (BUG) to be sold during exploration and appraisal, allowing for early revenue generation, payments of royalties to Native Title Owners and reduced flaring
- Tamboran signed a historic agreement with Native Title Holders and the Northern Land Council for the sale of appraisal gas from Exploration Permits in the Beetaloo Basin
- Agreement provides Native Title Holders' consent to the BJV to sell appraisal gas from the proposed SS Pilot Project of up to 60 TJ/d (~59 MMcf/d) over a three-year period
- The BJV are progressing to secure necessary approvals to support longer-term production

(1) Source: Australian Energy Market Operator (AEMO) 2024 Gas Statement of Opportunities (March 20, 2024), p.80.
(2) Source: Australian Gas Bulletin Board – Bonaparte Gas Pipeline flows (as at August 26, 2025).

Phase 1 – Gas contract

Initial gas from the Beetaloo Basin to be sold to the NTG, delivering energy security to Territorians

Channel Island Power Station. ~300 MW natural gas-fired power station located in Darwin

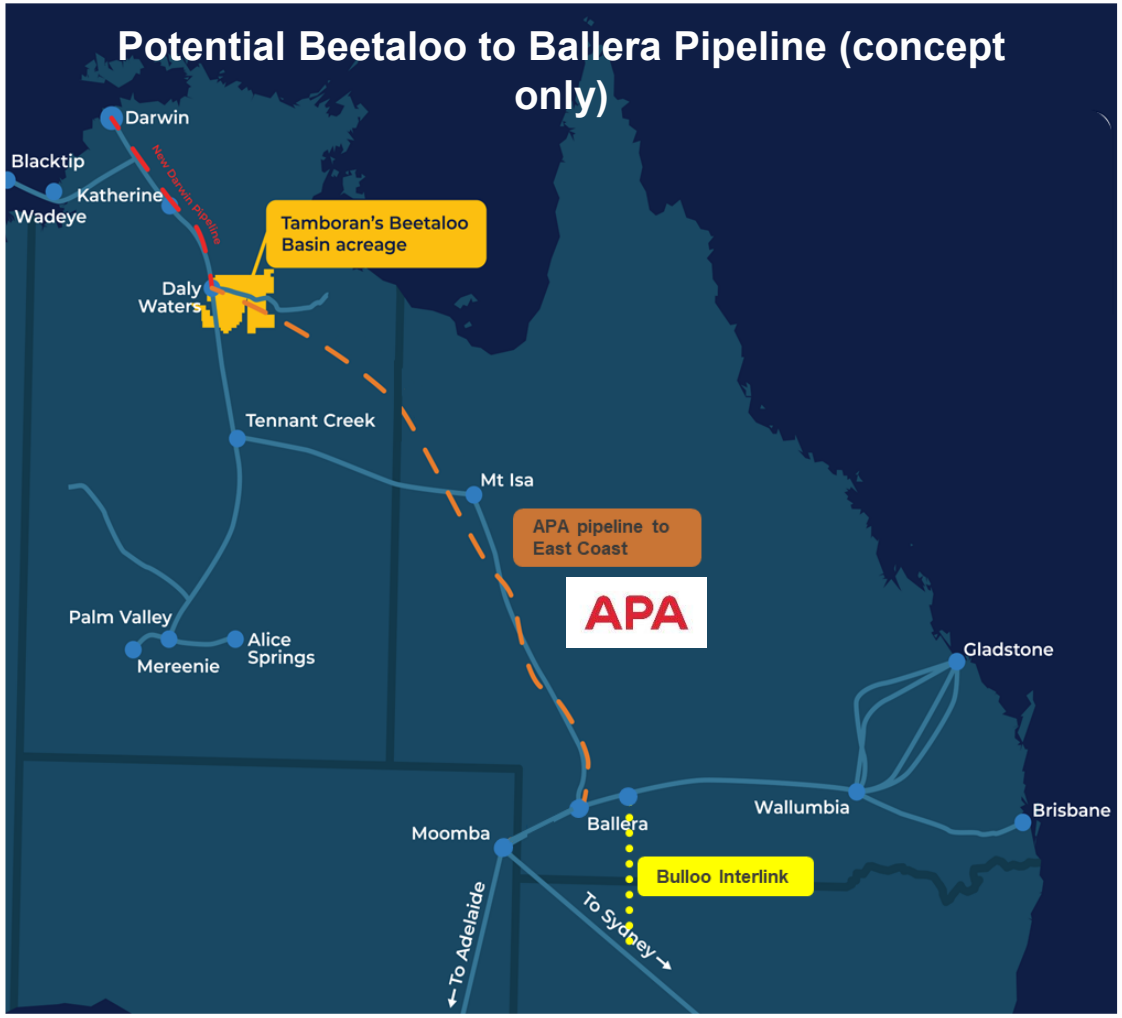
- **Customer:** Northern Territory Government (Aa3, stable) or its nominated assignee
- **Volume:** 40 TJ/d (~39 MMcf/d) (~19 TJ/d net Tamboran)
- **Term:** Total term of ~15 years. Initial 9-year term(1) with buyer's option to extend the GSA to mid-2041
- **Pricing:** Confidential (typical in the Australian gas market) on a take-or-pay basis at competitive market price, escalated at 100% Australian CPI
- **Delivery:** Entry into the APA-owned Amadeus Gas Pipeline (connecting Darwin to Alice Springs)
- **Strategy:** Targeting to support the Northern Territory with locally produced gas to provide energy security as primary gas supply from Blacktip declines
- **Connectivity:** Existing Amadeus Gas Pipeline (AGP) connects Beetaloo Basin to Weddell Power Station at Middle Arm

(1) Conditional on the BJV entering into a binding Gas Transportation Agreement with APA on the proposed Sturt Plateau Pipeline, a binding Gas Processing Agreement for the proposed Sturt Plateau Compression Facility, reaching a Final Investment Decision (FID), and receiving key regulatory and stakeholder approvals.

Phase 2 – Supply to the East Coast gas market

Opportunity to supply gas into the East Coast gas network via a new high pressure gas transmission pipeline from Beetaloo

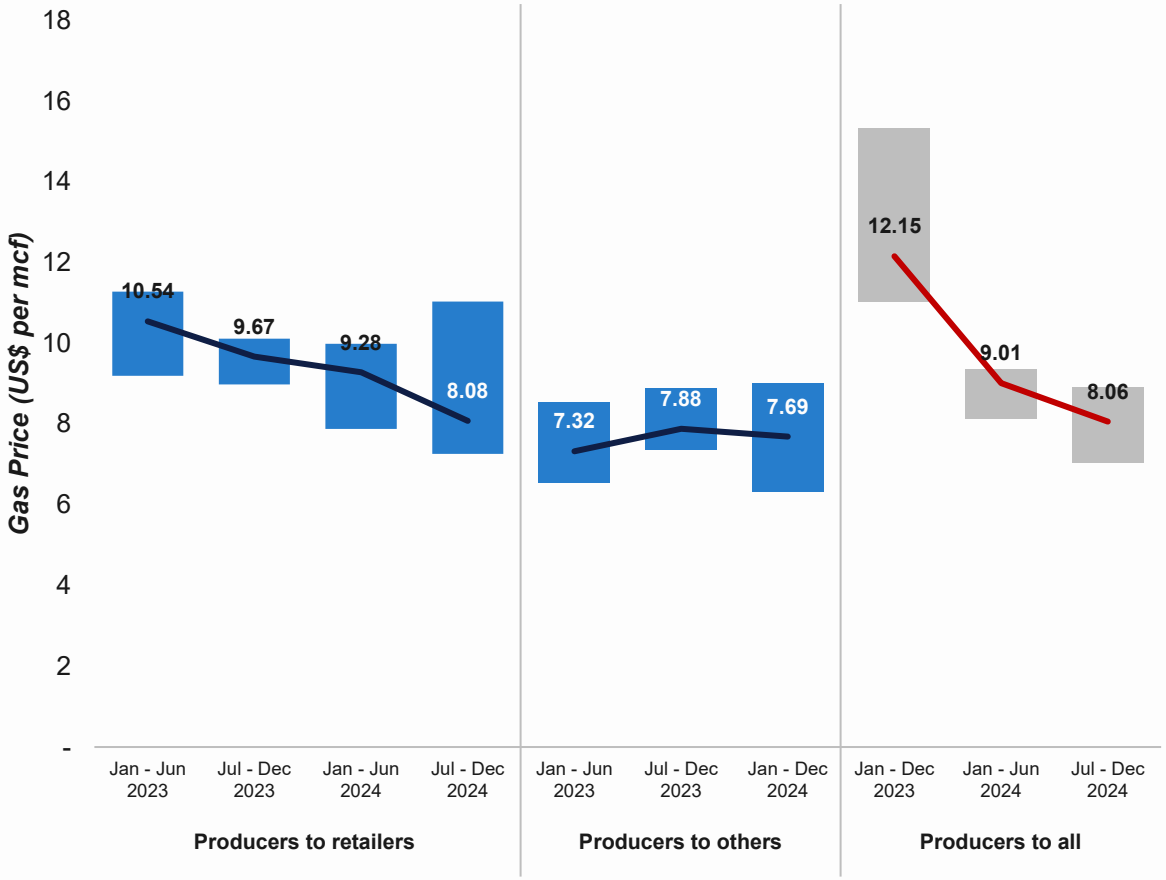
- Strong demand for Beetaloo Basin gas from six of the largest gas retailers on the East Coast
  - Non-binding LOIs for ~600 – 875 MMcf/d per day for up to 10 – 15 years (excluding Queensland LNG exporters)
- APA Group currently processing approvals and route selection for the 1,000-mile pipeline connecting the Beetaloo Basin to the East Coast gas market
- Pipeline expected to cost ~US$3 - 4 billion (based on ~600 MMcf/d of capacity)
- Indicative toll of US$1.25 – 1.75 per mcf, subject to total cost, capacity and amortization period
- Targeting FID in late 2027



Phase 2 – East Coast domestic gas price

~US$8 per mcf average contracted price for East Coast producers in 2025 | >200% higher than Henry Hub

Agreed gas prices to the East Coast market for 2025 supply(1)



- Australian gas contracts typically negotiated between buyer and seller over short- to medium-term period, with longer supply periods to support new fields and infrastructure
- Higher prices reflect lack of investment in new domestic gas supply and longer transport route to market
- Pricing confidential, however the ACCC releases gas offer and bid ranges throughout the year
- In June 2025, the ACCC announced average contracted East Coast price of ~US$8.00 per mcf between July and December 2024, a ~210% premium to Henry Hub pricing during that period

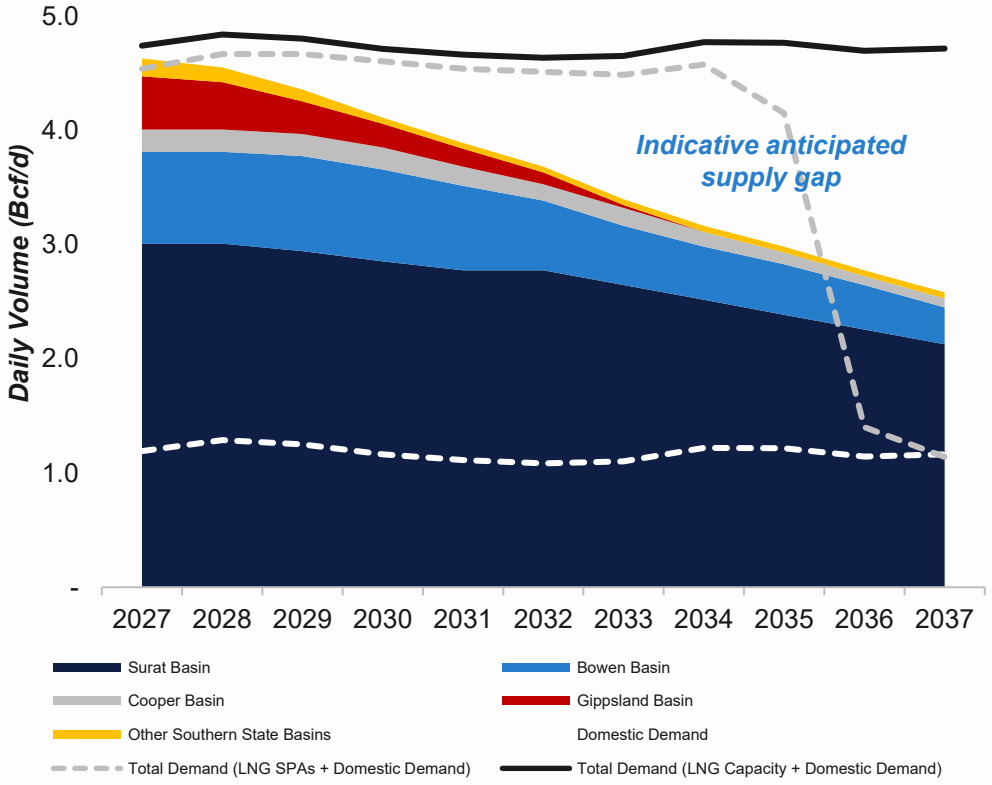
US$ per MMBtu	*Jul – Dec'24*
ACCC Reported Producer Offers(1)	8.06
Henry Hub(2)	2.60
Australian East Coast gas premium	**210%**

(1) Source: ACCC Gas Inquiry (2017 – 2030): Interim Update on East Coast gas market – June 2025 (p.28).
(2) Bloomberg (at August 21, 2025).

Phase 2 – East Coast gas market dynamics

Emerging shortfall on Australia's East Coast gas market provides near-term Beetaloo Basin opportunity

Forecast East Coast supply-demand outlook(1)



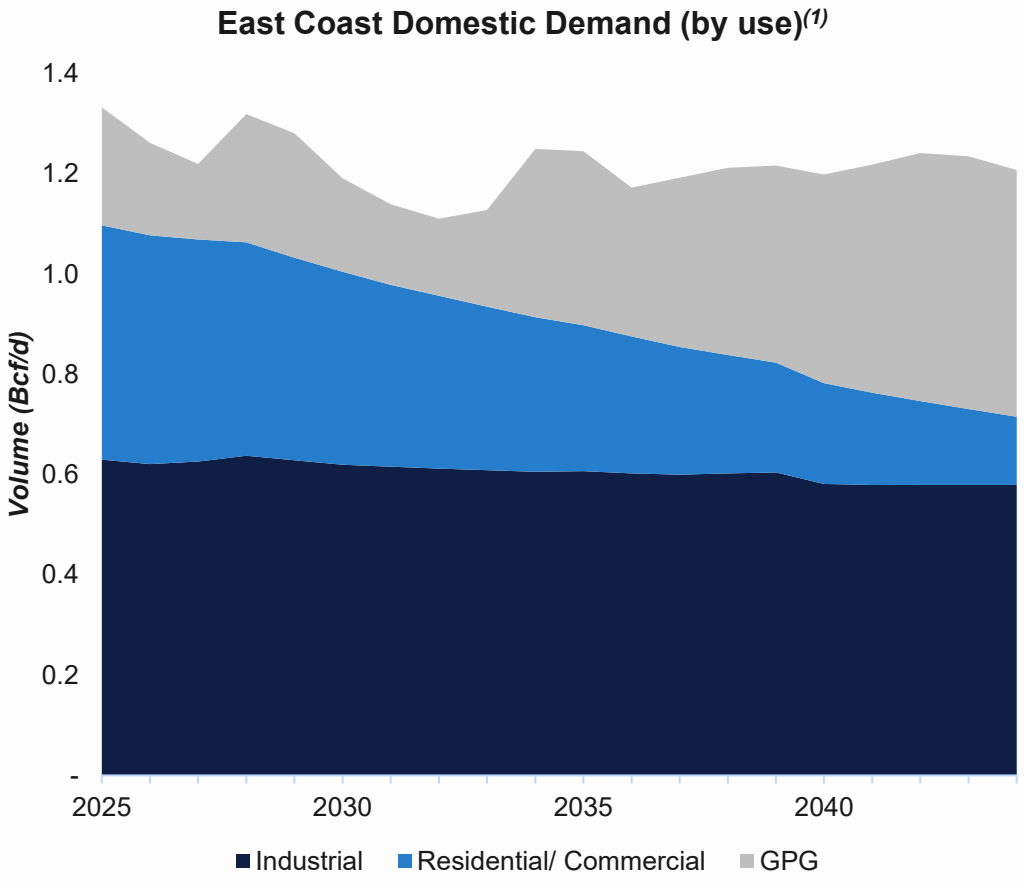
Australia's East Coast gas market has two key components:

- **Domestic demand:** ~1.3 Bcf/d forecast in 2025
  - Demand expected to decline ~10% by 2040 with fall in residential/commercial demand offset by increase in GPG demand to support renewable energy uptake
  - Domestic supply (based on 2P reserves) expected to decline in coming years leading to anticipated shortfall
- **LNG export capacity:** ~3.6 Bcf/d(2) (~25.3 MTPA)
  - ConocoPhillips-operated APLNG and Shell-operated QCLNG projects operating at capacity (20-year offtake contracts until mid-2030s)
  - Santos-operated GLNG project producing at 6 MTPA (capacity of ~7.8 MTPA)
  - Near-term opportunity for Beetaloo Basin to fill ullage in GLNG
  - Medium-term opportunity for backfill of QCLNG and APLNG projects beyond existing coal seam gas resource base

(1) Source: ACCC Gas Inquiry (2017 – 2030): Interim Update on East Coast gas market – June 2025 (p.45). ACCC analysis of data obtained from gas producers as at January 2025 and domestic demand from AEMO's March 2025 GSOO.
(2) Includes 6% fuel gas.

Phase 2 – East Coast domestic gas market dynamics

Domestic gas demand expected to remain resilient driven by an increase in GPG to support renewable energy stability



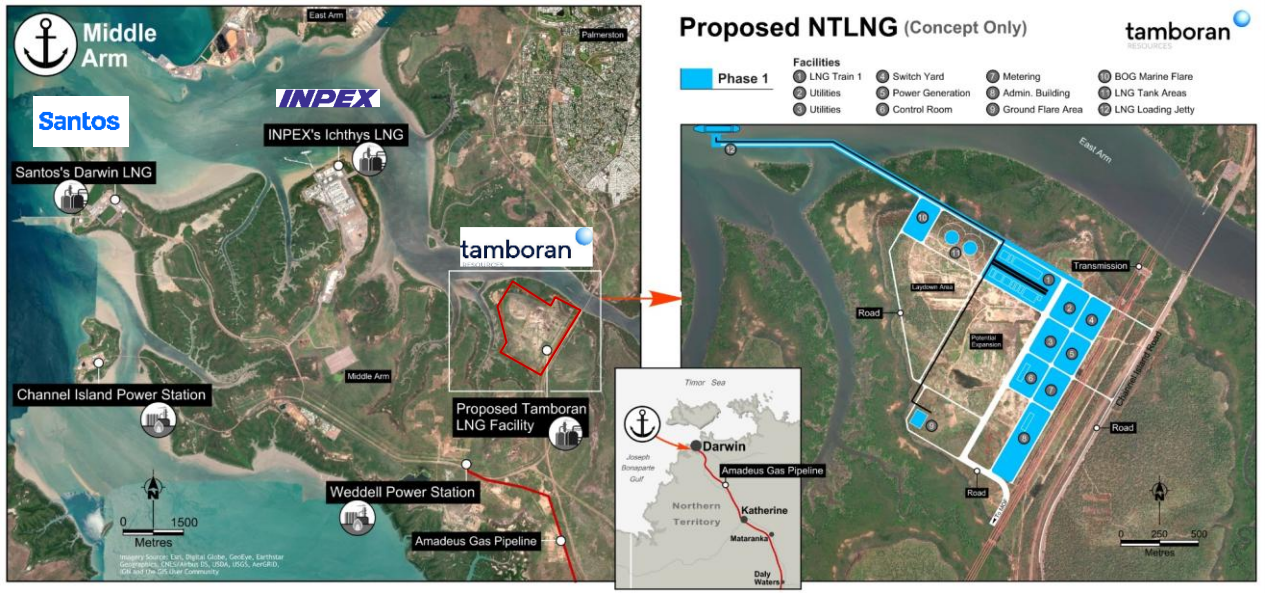
East Coast gas demand forecast(1)				
By industry		**2025**	**2040**	**Change**
Industrial	*Bcf/d*	0.6	0.6	*(8%)*
Residential/ Commercial	*Bcf/d*	0.5	0.2	*(57%)*
GPG	*Bcf/d*	0.2	0.4	*77%*
Total Domestic Demand	***Bcf/d***	***1.3***	***1.2***	*(10.1%)*

- ~1.3 Bcf/d of total domestic East Coast demand in 2025(1)
- Gas continues to play a critical role in firming renewables, especially in regions with limited grid storage. However, coal retirements and policy shifts may increase volatility
- Forecasts include limited potential increase in demand from roll out of data centres in Australia

(1) Source: AEMO Gas Statement of Opportunities 2025 (March 2025) (p.23)

Phase 3 – Tamboran's proposed NTLNG Project at Middle Arm, Darwin

Secured Middle Arm site to progress NTLNG | Targeting first fully integrated LNG development in onshore Northern Territory



Ichthys LNG Project on Middle Arm Sustainable Development Precinct

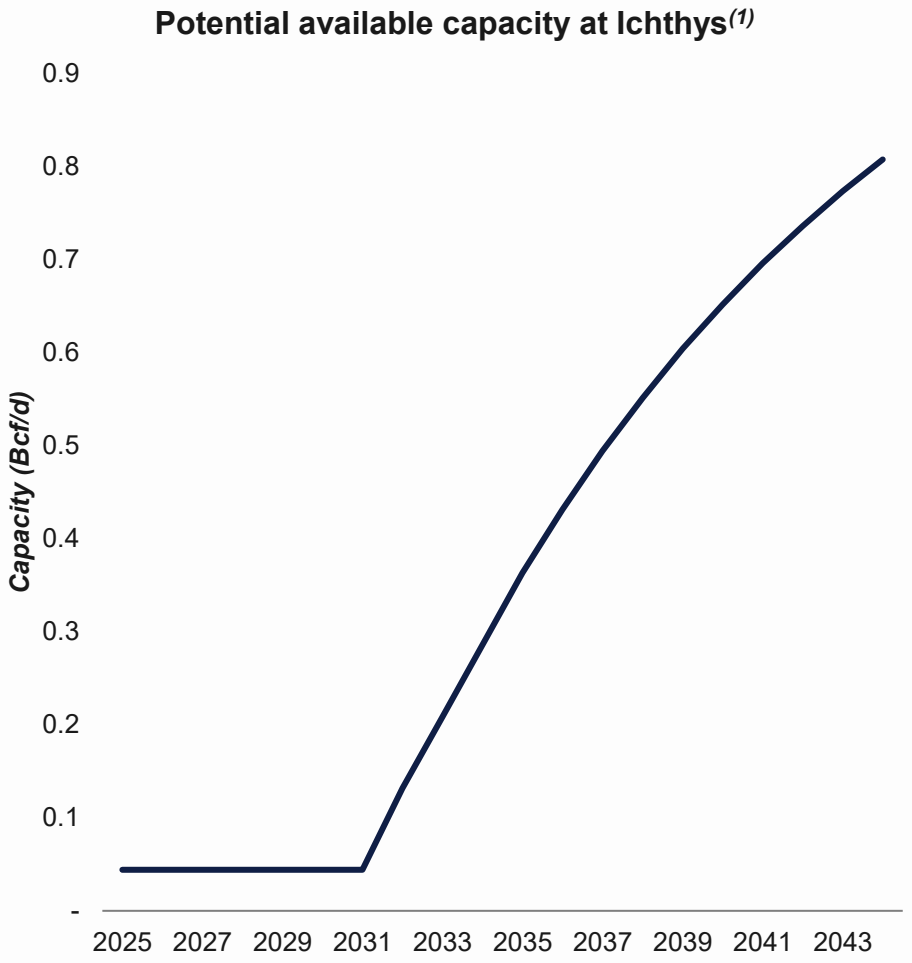
- **Northern Territory Government awarded Tamboran ~420-acre (170-hectare) site** at Darwin in May 2023
- **Signed an Interim Agreement to secure the site until the end of 2027**, with two one-year extension options to progress pre-FEED and FEED studies
- **Awarded pre-FEED studies to Bechtel**, world's most experienced LNG EPC contractor. Completed pre-FEED of first phase development consisting of 2x 6 MTPA LNG trains (12 MTPA).
- **Region-wide environmental approval process currently underway** by the NT Government, expected to be complete by end of 2025
- **The Australian Federal Government has indicated contribution of ~US$1.0 billion towards the development**(1) which could provide significant infrastructure
- Tamboran have signed **MOUs with bp and Shell for 2.2 MTPA of LNG each**

(1) Refer to Middle Arm Development Precinct website (The Precinct | Middle Arm Sustainable Development Precinct).

Phase 3 – Middle Arm LNG export opportunities

Available capacity at Darwin is driven by Ichthys LNG ullage and INPEX's offshore drilling success

- **INPEX-operated Ichthys LNG (8.9 MTPA):** Commenced production in 2018 with gas supplied from offshore fields to underpin LNG contracts
  - ~70% of Ichthys LNG is sold to Japan
  - Recent drilling results and reservoir underperformance may bring forward decline to early-2030s (as per Wood Mackenzie)
  - INPEX have announced studies for expansion train at Ichthys
- **Santos-operated Darwin LNG (3.7 MTPA):** Planning to commence production from offshore Barossa gas field in 2H 2025 and will be at full utilization until the late 2030s
  - Approvals in place for a ~6 MTPA brownfield expansion train on the existing site
  - Tamboran and Santos have signed an MOU to explore opportunities to supply planned expansion development with Beetaloo Basin gas



(1) Source: Wood Mackenzie Ichthys LNG (August 2024).

Glossary

AEMO	Australian Energy Market Operator
AGP	Amadeus Gas Pipeline
APA	APA Group (ASX: APA)
APLNG	Australia Pacific LNG
Bcf	Billion Cubic Feet
BJV	Beetaloo Joint Venture (TBN, DWE and Falcon Oil & Gas Australia Limited)
Bpm	Beats per minute
CDI	Chess Depositary Interest (200 CDIs = 1 NYSE Common Stock)
CSG	Coal Seam Gas
DWE	Daly Waters Energy, LP (Daly Waters Energy, LP are 100% owned by Formentera Australia Fund, LP, which is managed by Formentera Partners, LP, a private equity firm of which Bryan Sheffield serves as managing partner)
EP	Exploration Permit
EPC	Engineering, Procurement and Construction
FEED	Front End Engineering Design
FID	Final Investment Decision
ft	Feet
GSA	Gas Sales Agreement
H&P	Helmerich & Payne
IP90	Average production rate over the first 90 days of production
JV	Joint Venture
LNG	Liquefied Natural Gas
MTPA	Million tonnes per annum
MMcf/d	Million cubic feet per day
NT	Northern Territory
NTH	Native Title Holders
PJ	Petajoule
PL	Production Licence
SS	Shenandoah South
SPCF	Sturt Plateau Compression Facility
SPP	Sturt Plateau Pipeline
T2H/3H	Tanumbirini 2H/3H
TBN	Tamboran Resources Corporation
TD	Total Depth
TJ/d	Terajoule per day

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