tamboran RESOURCES

ANNUAL REPORT 24

30 JUNE 2024

NYSE: TBN | ASX: TBN | ARBN 672 879 024


SCF

CORPORATE DIRECTORY

Directors

Richard (Dick) Stoneburner

Joel Riddle

Fredrick Barrett

John Bell Sr.

Patrick Elliott

Hon. Andrew Robb AO

David Siegel

Stephanie Reed

Ryan Dalton

Chief Executive Officer

Joel Riddle

Chief Financial Officer

Eric Dyer

Chief Operating Officer

Faron Thibodeaux

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ARBN

672 879 024

Quoted on the Official List of
New York Stock Exchange
(Common Stock: TBN) and
Australian Securities Exchange
(via CHESS Depository Interests (CDIs))

CHAIRMAN'S LETTER

Mr. Richard (Dick) Stoneburner, Chairman

Thank you to our shareholders for your support throughout an exciting year in which Tamboran has continued unlocking the value of the vast natural gas resource within the Beetaloo Basin.

We remain focused on the development of the Beetaloo and delivering on our 2 billion cubic feet per day (Bcf/d) production ambition by end of 2030. This plan includes three phases, which prioritizes the local Northern Territory gas market ahead of a second East Coast gas supply phase, followed by our third LNG export phase.

This plan aims to generate significant job opportunities for Territorians, deliver substantial royalties to the Northern Territory Government and Native Title Holders, and provide Australian manufacturers and families with locally supplied natural gas.

As the global energy transition towards renewable technology continues, the need for natural gas in the energy mix is becoming clearer. Gas is essential for managing peaking power and replacing coal-fired power.

With onshore East Coast and offshore NT basins yielding more than double the in situ reservoir CO_2, I believe Tamboran is well positioned to play a key role in the decarbonisation efforts across Australia and the Asia Pacific.

The financial year commenced with Tamboran drilling two operated wells in the Beetaloo Basin with the newly imported Helmerich & Payne, Inc. (H&P) (NYSE: HP) super-spec FlexRig® Flex 3 Rig at the Shenandoah South and Amungee locations. Tamboran and H&P demonstrated the superior drilling efficiency of modern US equipment, which will help reduce future well costs and our environmental footprint.

The results from the drilling of the Shenandoah South 1H (SS-1H) well, the first well in the basin stimulated with modern US design techniques, achieved a normalized IP90 flow rate and decline curve that is analogous to some of the most productive regions of the Marcellus Shale in the US.

I believe the SS-1H results demonstrate the opportunity of the Mid Velkerri B Shale within the Beetaloo Basin and give me confidence to progress to our development stage of activities.

Tamboran and Liberty Energy (NYSE: LBRT) entered into a Strategic Partnership, including an equity investment, and have since mobilized modern US stimulation equipment into Australia. This fleet will be used to complete the Shenandoah South 2H (SS-2H) and 3H (SS-3H) wells in the fourth quarter of 2024.

We have also secured a strategic partnership with APA Group (ASX: APA), Australia's leading pipeline company. This allows us to progress our plans for pipeline infrastructure from the Beetaloo Basin. Bechtel Corporation (Bechtel), one of the world's leading LNG engineering, procurement and construction (EPC) contractors, also was recently awarded pre-FEED for our proposed NTLNG development at Middle Arm.

Finally, we achieved a significant milestone with our initial public offering and listing on the New York Stock Exchange (NYSE), becoming the first pre-revenue E&P company to list on the US market in approximately 15 years. The proceeds from the sale of our common stock on the NYSE will support the drilling of our 2024 wells, which will be some of the longest onshore wells drilled in Australia, further de-risking the flow rates from the Mid Velkerri B Shale over a 10,000-foot horizontal section.

I believe the access to the US market will support Tamboran in the long-term by providing access to capital and building upon our knowledge of shale development to support our endeavours to 2 Bcf/d of gross production from the Beetaloo Basin.

Finally, I would like to thank our key stakeholders, shareholders and employees for their support over the 2024 financial year. We will continue to focus our efforts on maximizing value from the Beetaloo Basin in a safe and environmentally conscious manner. I look forward to providing further updates over the course of the next 12 months as we progress towards first commercial production from the basin.

Sincerely,

Mr. Richard (Dick) Stoneburner
Chairman – Tamboran Resources Corporation

MANAGING DIRECTOR'S LETTER

Mr. Joel Riddle, Managing Director and CEO

Financial year 2024 has been Tamboran's most active year in the Beetaloo Basin with the drilling of two operated wells with the newly imported H&P super-spec FlexRig® Flex 3 Rig and the completion and flow testing of the SS-1H well.

The SS-1H result marked what we believe to be a tipping point in the de-risking of the Beetaloo Basin. The SS-1H well was completed with 5-1/2-inch casing, the first time this has been deployed in the Mid Velkerri B Shale in the basin to date. We achieved 100 barrels per minute with an optimized slickwater design with stimulation intensity of ~2,250 pounds per foot. This modern US completion design enabled Tamboran to achieve an average 90-day flow test of the SS-1H well at a 1,000m (3,281 foot) normalized average flow rate of 5.8 million cubic feet per day (MMcf/d), which was the highest normalized flow test in the Beetaloo Basin

The flow test of the SS-1H well is analagous to type curves from some of the most productive regions of the Marcellus Shale in the US, the largest and most prolific shale gas resource in the world.

We believe the SS-1H result, in conjunction with the 2022 flow results from the Tanumbirini 2H (T2H) and Tanumbirini 3H (T3H) wells validate Tamboran's long-standing thesis that the deeper sections of the Beetaloo Basin are correlated with the highest productivity reservoirs that have potential to deliver premium development economics, as compared to shallower areas of the basin.

We have also continued to progress key deliverables on our phased development strategy that will target delivery of up to 2 Bcf/d by the end of 2030.

In Phase 1 of our development strategy, the proposed 40 MMcf/d Shenandoah South Pilot Project is on track for production in 1H 2026, with final approvals anticipated by the end of 2024.

Since January 2024, Tamboran has completed FEED studies for the Sturt Plateau Compression Facility (SPCF) and Tamboran's Midstream Partner, APA, has continued to progress environmental approvals and engineering studies on the 30-mile pipeline from the SPCF to the Amadeus Gas Pipeline (AGP).

In May 2024, Tamboran announced the signing of a binding 15.5-year Gas Sales Agreement (GSA) with the Northern Territory Government for up to 40 terajoules (TJ) per day.

Importantly, the initial gas from the Shenandoah South Pilot Project is expected to be supplied directly into the Northern Territory local market, delivering on Tamboran's key promise of first gas from the Beetaloo Basin providing a direct benefit to all Territorians.

In Phase 2 of our development strategy, Tamboran has been actively working with APA to progress route selection and engineering studies for the construction of a new 36" pipeline from Tamboran's operated acreage in the Beetaloo Basin to the Australian East Coast Gas Market by 2028. In addition, Tamboran has continued to engage with the largest gas buyers in the Australian East Coast Market, where six potential buyers have expressed interest in purchasing up to 600 - 875 MMcf/d for up to 10 – 15 years. Tamboran will be targeting the conversion of these six Letters of Intent to binding GSAs and completion of the APA pipeline FEED studies by the end of 2026.

In Phase 3 of our development strategy, Tamboran was awarded 420-acre site at the Middle Arm Sustainable Development Precinct (MASDP) by the Northern Territory Government in June 2023. This site was exclusively awarded to Tamboran for its proposed NTLNG development. In January 2024, Tamboran completed a Concept Select study with Wood Group, which focused on the most appropriate liquefaction technology and overall design concepts for the NTLNG project.

In August 2024, Tamboran awarded Bechtel the EPC contract for pre-FEED studies at the proposed NTLNG project, which is expected to be completed by 2Q 2025. The decision to award Bechtel the scope of work followed a highly competitive process with some of the world most experienced EPC contractors and provides further validation for Tamboran's NTLNG project.

Tamboran has also continued to progress commercial discussions with bp and Shell, with the intent of converting the existing memorandums of understanding for 4.4 million tonnes of LNG each over 20-years, into binding LNG Sales and Purchase Agreements by the end of 2026.

We are excited to enter financial year 2025 with significant momentum. We commenced the drilling of the first Shenandoah South Pilot Project well, SS-2H in early August 2024, which will be immediately followed by the drilling of the SS-3H well from the same well pad. Both wells will be completed using the newly imported Liberty Energy frac fleet, which is expected to deliver significant improvements in completion efficiency in comparison to the SS-1H well.

The new Liberty frac fleet will simulate up to 60 stages across both the SS-2H and SS-3H wells later this year and each well has the potential to deliver the highest IP30 flow rates from any shale basin outside of North America.

Finally, I look forward to providing further updates as we progress the delivery of Tamboran's strategy that will target up to2 Bcf/d by the end of 2030. To be at the forefront of this new world-scale E&P development motivates me every day to continue to maximize value for our shareholders.

Sincerely,

Mr. Joel Riddle
Managing Director and CEO

REVIEW OF OPERATIONS

Tamboran Resources Corporation is focused on supporting the global energy transition by developing low-reservoir CO_2 gas resources within its portfolio (EP 136, EP 143, EP(A) 197, EP 161, EP 76, 98 and 117) located in the Beetaloo Sub-basin in the Northern Territory, Australia.

The Company is progressing towards commencing production from the proposed 40 MMcf/d Shenandoah South Pilot Project, which aims to supply gas volumes to the Northern Territory gas market in 1H 2026. The pilot project is expected to provide lessons and deliver resource maturation to support the sanctioning of a potential increase in domestic gas sales to the East Coast by 2028 and LNG development at Middle Arm in Darwin by the end of 2030.

Exploration Drilling

EP 76, 98 AND 117

EP 76, 98 and 117 - Tamboran holds a 38.75 per cent working interest (47.5 per cent working interest in 51,200 acres) and is the operator

Shenandoah South 1H (SS-1H)

In August 2023[2], Tamboran commenced the drilling of the SS-1H well with the H&P superspec FlexRig® Flex. The pilot hole reached a total depth (TD) of 10,827 feet (3,300 meters), intersecting approximately 295 feet (90 meters) of high quality Mid Velkerri B Shale with strong dry gas shows. The well intersected the thickest section of Mid Velkerri B Shale in the Beetaloo Sub-basin depocenter to date.

The pilot hole was drilled in 21.5 days, with logging of the Mid Velkerri B Shale formation indicating higher porosity and gas saturation relative to offset wells, analogous to the Marcellus Shale in the US. Initial evaluation confirms reservoir continuity of the Mid Velkerri B Shale over approximately 60 miles (~100 kilometers) between the Amungee 2H (A2H) and Beetaloo W1 (BW1) wells. This includes a target development area of approximately 1 million acres where the shale depth exceeds 8,800 feet.

The geological properties at the SS-1H location validate the Company's view that deeper shale areas in the Beetaloo Basin are likely to be the most prolific and optimal areas for the location of the proposed pilot project.

Following the pilot hole, the well was completed with a 3,524-foot (1,074-meter) horizontal section in a total of 41 days (~35 days excluding the drilling of the pilot hole). A 10-stage stimulation campaign was conducted in November 2023 and the well was suspended for pressure build-up and soaking prior to the commencement of flow testing.

In February 2024[3], Tamboran announced 30-day IP30 flow rates from the SS-1H well. The well flowed at 3.2 MMcf/d over the 1,644-foot (501 meter) stimulated length within the Mid Velkerri B Shale, normalized to 6.4 MMcf/d over 3,281-feet (1,000 meters).

Additional flow testing was reported over IP60[4] and IP90[5] periods, delivering 3.0 and 2.9 MMcf/d respectively, normalized for 6.0 MMcf/d and 5.8 MMcf/d over 3,281 feet (1,000 meters) respectively. The flow rates over the 90-day period exceeded Tamboran's pre-drill expectation and provide the Company with confidence to progress drilling activities during 2024 for the proposed ~40 MMcf/d Shenandoah South Pilot Project. The well has now been cased and suspended as a potential future production well.

During the SS-1H drilling activities[6], Tamboran gave notice to Falcon Oil and Gas Limited (Falcon) that all farm-in commitments have been fully satisfied, having reached the associated cost carry commitment in accordance with the 2014 Falcon farm-in agreement.

Amungee NW 3H (A3H)

Following completion of the SS-1H drilling activities, the H&P rig was mobilised to the Amungee pad and commenced drilling of the A3H well in EP 98 in late September 2023[7],[5]. The A3H well was drilled to a TD of 12,589 feet (3,837 meters) in 17.9 days, including a 3,773 foot (1,150-meter) horizontal section within the Mid Velkerri B Shale, a new Beetaloo Basin record.

The drilling activities were completed 20 days faster and approximately 30 per cent cheaper than the A2H well, which was completed to a TD of 3,883 meters (12,740 feet) from the same pad during the fourth quarter of 2022. The improved drilling speed and cost reduction at A3H demonstrate the improvement in drilling efficiency with the H&P Flex 3 Rig.

1. Subject to the completion of the SS-2H and SS-3H wells on the Shenandoah South pad 2
2. ASX Announcement 30 August 2023 – SS1H intersects 90m of high quality Mid Velkerri B shale
3. ASX Announcement 26 February 2024 – SS-1H IP30 Flow Test Results
4. ASX Announcement 26 March 2024 – SS-1H delivered IP60 flow test result
5. ASX Announcement 26 April 2024 – SS-1H achieved final IP90 commercial flow rates

Shenandoah South 2H (SS-2H) and 3H (SS-3H)

During the September 2024 quarter[14], the Company commenced the drilling of the first of two wells on the new Shenandoah South 2 (SS2) well pad in the proposed Shenandoah South Pilot Project area within EP 98. The SS-2H and SS-3H wells are being drilled with the H&P super-spec FlexRig® Flex 3 rig and are targeting the Middle Velkerri B Shale at a depth of approximately 9,910 feet (3,020 metres).

The wells are designed to include a 10,000-foot (3,000-metre) horizontal section and will each be stimulated with up to 60 stages utilizing the Liberty Energy modern frac fleet which has recently been mobilized from the US to Australia. The increased efficiency and performance of the Liberty frac fleet is expected to result in a material increase in the number of completed stages per day and optimized gas flows.

Both wells are planned to be flow tested and then suspended as future producing wells for Tamboran's proposed 40 MMcf/d Shenandoah South Pilot Project.

In May 2024, Tamboran received approval of its Environmental Management Plan (EMP) to construct up to four exploration and appraisal sites and undertake drilling and flow testing of up to 15 wells in EP 98 and EP 117.

EP 161

Santos holds a 75 per cent working interest and is the operator, Tamboran holds a 25 per cent working interest

During the reporting period[5], Santos, as operator of the EP 161 permit, completed the suspension activities of the T2H and T3H wells and continued the remediation of the Tanumbirini well pad following successful flow testing during 2022. The Inacumba well site was also rehabilitated by the operator.

The operator finalised the new Land Access and Compensation Agreement with the pastoralist, which includes provisions for the operator to progress the 2024 – 2025 work plan. The joint venture continues to plan a potential 200 – 240-kilometer (~125 – 150-mile) densely spaced 2D seismic survey in two areas over northern EP 161, with an EMP submitted to the Department of Environment, Parks and Water Security (DEPWS) and reconnaissance of the sites undertaken.

In the March quarter[8], the Northern Territory Government (NTG) accepted a permit variation by Santos, which included swapping two core hole wells for the stimulation of two future vertical wells.

EP 136, EP 143 AND EP(A) 197

Tamboran holds a 100 per cent working interest and is the operator

During the reporting period[5], Tamboran conducted routine well monitoring and lease maintenance on the Maverick 1V (M1V) well pad. The M1V well was completed in October 2022.

6. ASX Announcement 25 October 2023 – September 2023 Quarterly Activities Report
7. ASX Announcement 25 September 2023 – EP 98 Operational Update Spudding of A3H
8. ASX Announcement 30 April 2024 – March quarter Activities Report

"We have continued to progress key deliverables on our phased development strategy that will target delivery of up to 2 Bcf/d by the end of 2030."

– Mr. Joel Riddle,
Managing Director and CEO

Strategic Partnership with Liberty Energy

In December 2023[9], Tamboran announced it had entered into a Strategic Partnership and received a US$10 million equity investment from Liberty, a leading North American energy services firm.

Under the Strategic Partnership, Liberty has imported a modern frac fleet into the Beetaloo Basin to support future stimulation campaigns with industry leading operational and subsurface engineering expertise.

In August 2024, the stimulation equipment arrived in Darwin ahead of being mobilized to the Beetaloo Basin. The equipment is planned to be used to conduct up to 60 stimulation stages each within the 10,000-foot lateral sections of the SS-2H and SS-3H wells during the fourth quarter of 2024.

The efficiency and performance of the Liberty fleet are expected to result in a material increase in the completed stages per day, supporting long term cost reduction and optimised well performance.

Binding, long-term take-or-pay Gas Sales Agreement with Northern Territory Government

In April 2024[10], Tamboran and the Beetaloo Joint Venture (BJV) signed a binding long-term GSA to supply the NTG with 40 terajoules (TJ) per day (~19 TJ per day net to Tamboran) from the proposed Shenandoah South Pilot Project for an initial term of nine years (131.4 petajoules (PJ) Total, ~62.4 PJ net to Tamboran), starting in H1 2026. The NTG has an option to extend the GSA for a further six-and-a-half years through to mid-2041.

Gas will be delivered to the NTG at the APA owned AGP on a take-or-pay basis at a market-competitive gas price, escalating at 100% of the Consumer Price Index (CPI). The NTG's extension option is at a slightly discounted price.

The binding supply commitment is conditional on the BJV entering into a binding Gas Transportation Agreement with APA on the proposed SPP, a binding Gas Processing Agreement for the proposed SCPF, reaching Final Investment Decision, and receiving key regulatory and stakeholder approvals.

Tamboran is targeting first production from the proposed Pilot Project in 1H 2026.

9. ASX Announcement 15 December 2023 – Tamboran enters Strategic Partnership with Liberty Energy
10. ASX Announcement 23 April 2024 – Tamboran sign binding GSA with Northern Territory Government

Key agreements executed with pipeline partner, APA Group

During the December quarter[11], Tamboran announced the three formal and binding agreements with APA Group to support the development of the Company's Beetaloo Basin assets, including:

- An Early Development Agreement relating to the construction of a ~35-kilometer SPP that is planned to connect the proposed 40 MMcf/d SPCF to the AGP, targeting an online date as early as 2H 2025, subject to achieving project milestones and executing further agreements;
- An Early Development Agreement for construction of a Beetaloo Basin to East Coast gas pipeline that aims to deliver in excess of 500 MMcf/d of Beetaloo Basin gas into Australia's East Coast gas market, targeting an online date as early as 2028, subject to achieving project milestones and executing further agreements; and
- A Partnering Agreement under which Tamboran agrees to work exclusively with APA Group and provides an option for Tamboran to acquire up to 15 per cent of any Beetaloo pipeline projects in the lead up to Final Investment Decision (excluding the SPP), subject to certain conditions being met.

Under the Early Development Agreements, APA has agreed a process to continue development of the proposed pipelines with early works expenditure of up to A$10 million on the basis that Tamboran continues to progress and achieve agreed milestones in relation to the proposed Shenandoah South Pilot Project.

Six letters of Intent signed with Australia's largest gas and energy retailers

During the September 2023 quarter[11,12], Tamboran announced it had signed six LOIs with Australia's largest gas and energy retailers, including Alinta, EnergyAustralia, Engie, Origin Energy and Shell Energy Australia. The LOIs express interest for a total volume of 600 – 875 TJ per day (220 – 320 PJ per annum) of Tamboran's Beetaloo Basin gas supply for up to 10 – 15 years.

The LOIs are conditional upon the Parties agreeing non-binding term sheets and working toward executing binding GSAs, including purchase price, transport arrangements and other key commercial terms.

Increase in the Shenandoah South Pilot Project interest to a minimum of 47.5%

In March 2024[13], Falcon Oil & Gas (Australia) Limited made the decision to limit its participation to 5.0% in the Beetaloo Joint Venture's (BJV) SS2 well pad and the two wells in the 2024 drilling program drilled from that pad.

The two wells in the 2024 drilling program will create two Drilling Spacing Units (DSUs) totalling 51,200 gross acres around the new SS2 well pad, where Tamboran and Daly Waters Energy, LP (DWE) as 50/50% owners of Tamboran (B2) Pty Limited have agreed to pick up the non-consent, increasing interest to 95.0%.

Tamboran and DWE will carry Falcon for up to A$3.75 million gross (A$1.875 million net) for the first well post 30 June 2024.

The 51,200 gross acre area has the potential to accommodate 23 well pads (138 wells based on six wells per pad, 3,000-meter lateral sections and 500 meter well spacings) and it is expected to support the wells required to deliver gas to the proposed Shenandoah South Pilot Project.

11. ASX Announcement 18 December 2023 – Tamboran progresses key pipeline agreements with APA Group
12. ASX Announcement 2 August 2023 – Tamboran signs LOI's with four domestic buyers
13. ASX Announcement 28 August 2023 – Tamboran signs additional East Coast gas LOI's
14. ASX Announcement 25 March 2024 – Tamboran increases Pilot interest to a minimum of 47.5%

NTLNG development at Middle Arm, Darwin

In 2024[7,15], Tamboran completed Concept Select Engineering studies with Wood Group for the Company's proposed NTLNG development at Middle Arm, Darwin. The engineering work has defined and selected the key LNG plant specifications including liquefaction technology, compressor driver configuration, LNG capacity and draft facility layout on Tamboran's 170-hectare (440-acre) site in the Middle Arm Sustainable Development Precinct near Darwin.

In August 2024, Tamboran awarded Bechtel, a leading EPC contractor, pre-FEED activities for Tamboran's proposed NTLNG project at Middle Arm in Darwin. Pre-FEED activities are expected to be completed in 1H 2025 ahead of progression to FEED activities, subject to securing strategic partner and funding.

Interim Agreement with NTG over Middle Arm site

In July 2024[16], Tamboran was granted an Interim Agreement by the NTG over its 440-acre (170-hectare) site at the Middle Arm Sustainable Development Precinct.

The agreement provides Tamboran with future exclusivity over the Wirraway North land until the end of 2027 with two 1-year extension periods and maps out how the Crown Lands department will work with the Company for future development of the site. The Interim Agreement is expected to be in place until it is replaced by a Commercial Lease document just prior to Final Investment Decision.

Tamboran granted Major Project Status by Northern Territory Government

In June 2024[17], Tamboran was granted Major Project Status by the NTG for the development of its Beetaloo Basin assets.

Major Project Status provides Tamboran with significant benefits, including;

- NTG acknowledgement of the Beetaloo Basin's significance to the Territory's economic prosperity,
- Continuing support for Tamboran as it progresses its local development plans in the Beetaloo Basin, with first gas being supplied to Territorians ahead of the target East Coast domestic gas and LNG export projects,
- Regulatory approval process mapping, and
- A dedicated project case manager to assist with coordinated and streamlined communications within Government.

The recognition of Major Project Status demonstrates the NTG's support for Tamboran's integrated development of the Beetaloo Basin that aims to provide energy security and significant job opportunities for the people of the Northern Territory.

15. ASX Announcement 25 July 2023 – Wood awarded NTLNG Concept Study Contract
16. ASX Announcement 31 July 2024 – June Quarter Activities Report
17. ASX Announcement 19 June 2024 – Tamboran's Beetaloo Project awarded Major Project Status

Redomiciliation and Initial Public Offering on New York Stock Exchange (NYSE)

In mid-October 2023[18], Tamboran announced the intention to re-domicile the Company and its subsidiaries from Australia to the United States of America by way of a proposed Scheme of Arrangement. On December 1, 2023[19], shareholders voted in favour of the decision at a Scheme Meeting. The scheme became effective[20] as of December 7, 2023 following the lodgement of the orders of the Federal Court with the Australian Securities and Investments Commission.

On June 27, 2024[21], Tamboran announced the pricing of its initial public offering of 3,125,000 shares of Common Stock at a price of US$24.00 per share to the public on the New York Stock Exchange (NYSE), raising gross proceeds of US$75 million.

At the end of July 2024, the underwriters of the IPO exercised their option to purchase an additional 308,750 shares at US$24.00 per share, raising an additional US$7.4 million (before fees).

The IPO was supported by a US$20 million investment from existing shareholders Sheffield Holdings, LP (an affiliate of Bryan Sheffield) and Liberty Energy.

Tamboran shares commenced trading on the NYSE on 27 June 2024, under the ticker symbol "TBN" and the offering was successfully completed on 28 June 2024. Securities in Tamboran continue to be traded on the ASX via CHESS Depository Interests (CDIs).

"2024 has been Tamboran's most active year in the Beetaloo Basin with the drilling of two operated wells."

– **Mr. Joel Riddle**, Managing Director and CEO

18. ASX Announcement 12 October 2023 – Tamboran announces intention to re-domicile to the US
19. ASX Announcement 1 December 2023 – Results of Scheme Meeting
20. ASX Announcement 7 December 2023 – Scheme of Arrangement becomes effective
21. ASX Announcement 24 June 2024 – Tamboran prices US IPO at US$24.00 per share

Capital Raisings

During the reporting period, the Company completed two successful capital raisings to progress its development activities within its Beetaloo Basin assets.

A$55 MILLION RAISING – DECEMBER 2023

In mid-December 2023[22], Tamboran announced the Company had successfully raised A$40.8 million via an Institutional Placement and institutional component of the 1 for 6.2 pro rata accelerated non-renounceable Entitlement Offer. The raise was conducted at A$0.16 per new CDI. The raise was supported by a A$7.6 million pre-commitment from the Company's largest shareholder, Mr. Bryan Sheffield, a US$10 million (A$15.2 million) strategic placement from Liberty and existing US and UK shareholders.

The Company announced the completion of the Retail Entitlement Offer in mid-January 2024, which raised an additional A$14.2 million, completing a total raise of A$55.0 million. The funds from the capital raise have been used to support Tamboran's activities, including SS-1H flow testing and purchase of long lead items, to the sanctioning of the proposed 40 MMcf/d Shenandoah South Pilot Project.

US$82 MILLION RAISING ASSOCIATED WITH NYSE IPO

As noted above, in June 2024[23], Tamboran announced the issue of 3,125,000 shares of Common Stock at a price of US$24.00 per share, raising gross proceeds of US$75 million (before fees), as part of its IPO on the NYSE.

Post the end of the reporting period, at the end of July 2024[23], the underwriters of the IPO exercised their option to purchase an additional 308,750 shares at US$24.00 per share, raising an additional US$7.4 million (before costs).

BofA Securities, Citigroup, and RBC Capital Markets acted as joint book-running managers for the offering. Johnson Rice & Company and Piper Sandler acted as co-managers.

CONVERSION OF HELMRICH & PAYNE CONVERTIBLE NOTE

In June 2024[16], Tamboran finalized and issued the US$9 million convertible note with H&P, which was granted to fund mobilization of the FlexRig® Flex 3 Rig from the United States to Australia in 2023. The final terms of the note allowed for the note to be converted to equity at the IPO at a 20% discount to the final offer price.

In conjunction with the IPO, H&P elected to convert the Convertible Note and were issued 489,088 shares of Common Stock reflecting the US$9 million value plus US$0.4 million in accrued interest at the IPO discount price of US$19.20 per share.

22. ASX Announcement 14 December 2023 – Tamboran announces launch of equity raise
23. ASX Announcement 30 July 2024 – Partial exercise of underwriters over-allotment option

GAS MARKETS

Tamboran aspires to deliver 2 Bcf/d in gross production from the Company's operated Beetaloo assets.

The Company holds between 38.75% and 47.5% interest in key assets that are planned to deliver this volume across three key markets;

- Local Northern Territory gas market
- Australia's East Coast domestic gas market
- The international LNG market

Tamboran believes Beetaloo Basin gas, with its inherently low reservoir carbon dioxide content, can play a major role in Australia and our trading partner's energy transition, by firming renewable energy and displacing coal fired power.

Local Northern Territory Gas Market

Local gas demand in the Northern Territory is ~70 MMcf/d, mainly used in power generation. There are a number of gas fired power stations across the Northern Territory, with the largest generators located on Middle Arm near Darwin, supplying power to local homes and businesses.

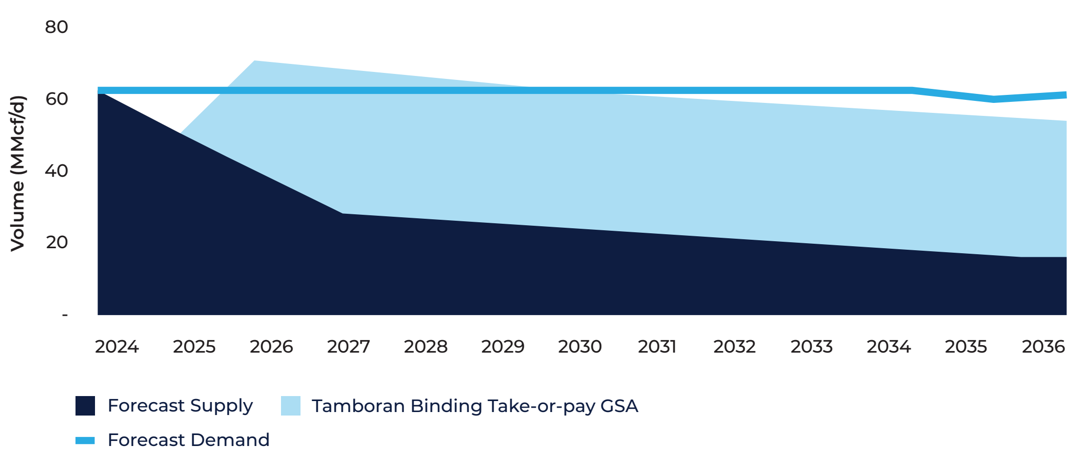
Historically, the Northern Territory has been supplied by two main fields, the onshore Mereenie fields, operated by Central Petroleum (ASX: CTP) and the offshore Blacktip gas field, operated by Eni.

Since 2021, production from the Blacktip field started to materially decline, resulting in potential shortfalls in the local gas market.

The Northern Territory has been forced to divert gas volumes from export LNG at significantly higher prices to maintain gas supply to the power stations.

The under-performance of the Blacktip field provides Tamboran with an opportunity to accelerate first gas to meet the potential shortage in gas supply for the Territory. In April 2024 Tamboran signed a binding, long-term take-or-pay GSA with the Northern Territory Government to supply up to 40 TJ/d for up to 15.5 years. This gas will be crucial in maintaining energy security for Darwin and surrounding areas.

AEMO Northern Territory Supply/Demand Forecast[1]



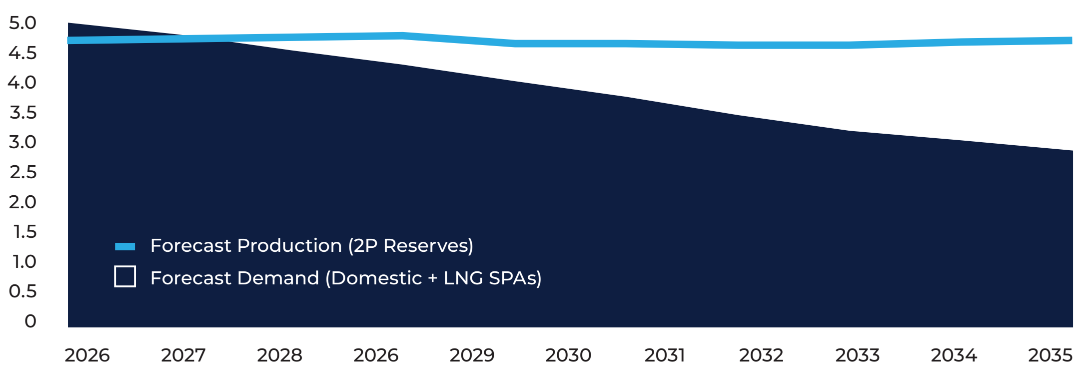
Source: Australian Energy Market Operator (AEMO) 2024 Gas Statement of Opportunities (March 21, 2024), p.74

Australia's East Coast Gas Market

All market analysts, including both the Australian Competition and Consumer Commission (ACCC) and Australian Energy Market Operator (AEMO) continue to forecast gas shortfalls this decade as new local gas production declines and few gas projects of significance are developed to offset the decline.

The ACCC's latest report from July 2024 is now forecasting a gas shortage in the winter of 2027, a year earlier than previously estimated due to "lower forecast supply due to delays in anticipated regulatory approvals for new projects and problems with legacy gas fields".

ACCC East Coast gas supply/demand forecast (Including Domestic and LNG SPAs via Gladstone)



Source: ACCC June 2024 Interim Report (July 5, 2024)

Natural gas on the East Coast plays a vital role in various sectors. Gas power generation is essential for maintaining the stability and reliability of the electricity grid. This role will become increasingly important as more renewable energy sources integrated into the market and coal fired power plants are decommissioned. Around 21% of gas demand on the East Coast is used by the residential and commercial sector, primarily for heating, cooking and providing hot water. A further 43% is used in the industrial sector, as a fuel for high temperature processing of metals and glass, as well as a chemical feedstock in the production of fertilizers, explosives and various plastics.

There continues to be strong interest from East Coast gas buyers in gas from the Beetaloo Basin. Tamboran is working with APA, Australia's largest midstream company, to develop a new pipeline to connect the Beetaloo Basin to the East Coast gas grid. APA has commenced early Access & Approvals work at its own cost, and is very supportive of connecting the Beetaloo to the market.

In 2023, Tamboran signed non-binding Letters of Intent with Australia's six largest gas buyers for a total potential volume of 600 – 875 TJ per day (~220 – 320 PJ per annum) for up to 10 – 15 years. Management will continue to mature these LOIs into fully termed Gas Sales Agreements over 2025/26 ahead of an anticipated final investment decision for Tamboran's Phase 2 East Coast gas project by late 2026 or early 2027, subject to securing key stakeholder approvals and financing.

There are currently three LNG projects located at Gladstone that are connected into the East Coast gas grid. There is already ullage in some of these facilities, and this is expected to grow over the coming years, representing another opportunity for Beetaloo gas.

With Australian gas sales typically priced through company-to-company negotiations and an illiquid spot market, pricing transparency has historically been limited. The ACCC requires gas producers to disclose their pricing discussions and contracts and reports three times per year on a no-names basis.

The ACCC Interim Report (June 2024) highlighted that gas prices contracted for 2024 supply fell to ~A$12.60 per GJ (~US$8.45 per MMBtu), reflecting a >280% premium to Henry Hub. This increase to A$15.02 per GJ (US$10.00 per MMBtu) for 2025 supply.

International LNG markets

Tamboran's Phase 3 gas development plans are for LNG export out of the MASDP near Darwin. A new 650km pipeline will be required to connect the Beetaloo fields to MASDP.

Tamboran is planning on a new LNG export facility located at MASDP. This project, called NTLNG, will be situated on 420 acres of land that been secured from the NT Government which will provide sufficient area for the construction of up to 4 LNG trains. In February 2024 Tamboran completed the Concept Select phase for Train 1 of NTLNG, sized nominally at 6.5 MTPA (million tonnes per annum) which is approximately equivalent to 1 bcf/d of feed gas.

In August 2024 Tamboran awarded Pre-FEED to Bechtel, and anticipates that phase will be complete in 2Q2025.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended June 30, 2024

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 001-42149

Tamboran Resources Corporation

tamboran
RESOURCES

(Exact name of Registrant as specified in its Charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**93-4111196** **(I.R.S. Employer Identification No.)**
Suite 01, Level 39, Tower One, International Towers Sydney **100 Barangaroo Avenue, Barangaroo NSW** **(Address of principal executive offices)**	**2000** **(Zip Code)**

Registrant's telephone number, including area code: Australia +61 2 8330 6626

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, $0.001 par value	TBN	New York Stock Exchange

Securities registered pursuant to section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒	Smaller reporting company	☒
		Emerging growth company	☒

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The registrant was not a public company as of the last business day of its most recently completed second fiscal quarter and, therefore, cannot calculate the aggregate market value of its voting and non-voting common equity held by non-affiliates as of such date.

As of September 20, 2024, the number of shares outstanding of the registrant's common stock was 14,224,274.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Tamboran Resources Corporation Proxy Statement for the Annual Meeting of stockholders to be held November 4, 2024 ("2024 Proxy Statement") are incorporated by reference into Part III hereof.

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GLOSSARY OF TERMS

Throughout this Annual Report on Form 10-K (or this "report"), the following company or industry specific terms and abbreviations are used:

"*analogous reservoir*" refers to analogous reservoirs, as used in resources assessments, having similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an analogous reservoir refers to a reservoir that shares the following characteristics with the reservoir of interest: (i) same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) same environment of deposition; (iii) similar geological structure; and (iv) same drive mechanism.

"*appraisal well*" refers to a vertical or horizontal well designed to assess the properties of the prospective formation by performing open hole logging activities, diagnostic fracture injection testing, fracture stimulation, flow testing, or any combination of the above for the purpose of formation evaluation. Our use of the term "appraisal well" correlates to the term "exploratory well" as defined in Rule 4-10(a) of Regulation S-X.

"*ASX*" refers to the Australian Securities Exchange.

"*Beetaloo*" refers to the Beetaloo Basin of the Northern Territory, Australia.

"*Beetaloo Joint Venture*" refers to the unincorporated joint venture in respect to EPs 76, 98 and 117, between TB1 Operator (77.5% working interest) and Falcon (22.5% non-operated working interest).

"*Bcf*" refers to one billion cubic feet.

"*Bcf/d*" refers to one billion cubic feet per day.

"*bp*" refers to BP Singapore Pte. Ltd, a subsidiary of BP plc.

"*Btu*" refers to British thermal unit, which is the heat required to raise the temperature of one pound of liquid water by one degree Fahrenheit.

"*CDI*" refers to a CHESS Depository Interest.

"*CO2*" refers to carbon dioxide.

"*CO2-e*" refers to carbon dioxide equivalent.

"*completion*" refers to the installation of permanent equipment for production of oil or gas.

"*Corporate Reorganization*" refers to the transactions pursuant to which, among other things, we (i) issued to eligible shareholders of TR Ltd. one CDI of our common stock for every one ordinary share of TR Ltd., in each case, as held on the scheme record date, (ii) amended the terms of each of the outstanding options to acquire ordinary shares of TR Ltd. so that the entitlements of option holders to be issued ordinary shares in TR Ltd. instead became entitlements to be issued CDIs in the Company, (iii) maintained an ASX listing for our CDIs, with each CDI representing 1/200th of a share of our common stock, (iv) delisted TR Ltd.'s ordinary shares from the ASX, and (v) became the parent company to TR Ltd.

"*Corporations Act*" refers to the Australian Corporations Act, 2001 (Cth).

"*Daly Waters*" or *"DWE*" refers to Daly Waters Energy, LP, which is 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.

"*Daly Waters Placement*" refers to the intended issuance at the closing of the offering of $7.5 million in shares of our common stock at the initial public offering price to Daly Waters, or its nominee, in satisfaction of certain payment obligations under the TB1 Joint Venture Agreement. See "*Business and Properties—Agreements Relating to the Development of our Assets.*"

"Daly Waters Royalty" refers to Daly Waters Royalty, LP.

"*developed acres*" refers to the number of acres that are allocated or assignable to productive wells.

"*development well*" refers to a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"*drilling space unit*" or "*DSU*" refers to the area allocated to a well for the purpose of drilling for or producing oil or gas.

"*ESG*" refers to environmental, social and governance.

"*estimated ultimate recovery*" or "*EUR*" refers to the sum of reserves remaining as of a given date and cumulative production as of that date.

"*exploratory well*" refers to a well drilled to find or establish a new productive oil or natural gas reservoir, or to delineate the extent of a known productive reservoir.

"*extension well*" refers to a well drilled in an effort to extend the limits of a known productive reservoir.

"farmin agreement" refers to an agreement under which the owner of a working interest in license assigns the working interest or a portion of the working interest to another party (the *"farmee"*) as a means to share the costs and risks of development. Generally, the farmee agrees to pay the cost of the working interest owner (the *"farmor"*) to drill one or more wells. As consideration for the farmee's services, the farmor transfers to the farmee a portion of the farmor's interest in the license.

"*Falcon*" or "*FOG*" refers to Falcon Oil and Gas Australia Ltd, a wholly owned subsidiary of Falcon Oil and Gas Limited (TSX.V: FOG, London AIM: FO).

"*Australian Federal Government*" refers to the federal government of Australia.

"*frac*" refers to the drilling method for extracting oil and natural gas.

"*GAAP*" refers to generally accepted accounting principles in the United States.

"*GHG*" refers to greenhouse gases.

"*gross acres*" or "*gross wells*" refers to the total acres or wells, as the case may be, in which a working interest is owned.

"*H&P*" refers to Helmerich & Payne International Holdings, LLC, a subsidiary of Helmerich and Payne, Inc. (NYSE: HP).

"*Henry Hub*" refers to a natural gas pipeline located in Erath, Louisiana that serves as the official delivery location for futures contracts on the NYMEX. The settlement prices at the Henry Hub are used as benchmarks for the North American natural gas market.

"IP30" refers to 30-day initial production.

"IP60" refers to 60-day initial production.

"*IP90*" refers to 90-day initial production.

"*Mcf*" refers to one thousand cubic feet.

"*MMBtu*" refers to one million Btus.

"*MMcf/d*" refers to one million cubic feet per day.

"*Mtpa*" refers to million metric tons per year.

"*net acres*" refers to the gross acres on which an owner holds an interest, proportionally reduced by the working interest in such acreage. For example, an owner who has 50% interest in 100 acres owns 50 net acres.

"*net wells*" refers to the gross wells on which an owner holds an interest, proportionally reduced by the working interest in such wells. For example, an owner who has 50% interest in 100 wells owns 50 net wells.

"*net zero equity*" refers to the elimination and/or offset of GHG emissions, on an equity share basis, for the relevant emission scopes referred to.

"*Northern Territory*" refers to the Northern Territory of Australia.

"*operational net zero*" refers to the full elimination and/or offset of Scope 1 and Scope 2 emissions in our upstream businesses, based on an equity share approach.

"*Origin Energy*" refers to Origin Energy Limited (ASX: ORG).

"*Origin Retail*" refers to Origin Energy Retail Pty Ltd., a subsidiary of Origin Energy.

"*ORRI*" refers to overriding royalty interest.

"*petrophysical analysis*" refers to the integration and analysis of various data types, including well logs, core samples and fluid samples and comparison of data with other relevant geological and geophysical information to describe the reservoir properties.

"*Petroleum Act*" refers to the *Petroleum Act 1984* (NT).

"*probable reserves*" refers to additional reserves that are less certain to be recognized than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

"*productive well*" refers to an exploratory, development, or extension well that is capable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

"*prospective resources*" refers to quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

"*proved reserves*" refers to quantities of oil, natural gas and NGLs that, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or we must be reasonably certain that it will commence within a reasonable time. For a complete definition of proved crude oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

"*reserves*" refer to estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

"resources" refers to quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

"*royalty interest*" refers to an interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

"*Santos*" or "*Santos QNT*" refers to Santos QNT Pty Ltd, a wholly owned subsidiary of Santos Ltd (ASX: STO).

"*scheme of arrangement*" refers to a statutory scheme of arrangement under Australian law under Part 5.1 of the Corporations Act.

"*Scope 1 emissions*" refers to direct GHG emissions that occur from sources that are controlled or owned by an organization.

"*Scope 2 emissions*" refers to indirect GHG emissions associated with the purchase of electricity, steam, heat or cooling.

"*Scope 3 emissions*" refers to GHG emissions that result from the end use of an organization's products, as well as emissions from other business activities from assets not owned or controlled by the organization but that the organization indirectly impacts in its value chain.

"*Shell*" refers to Shell Eastern Trading (Pte) Ltd, a subsidiary of Shell plc (NYSE: SHEL).

"*Tamboran*" refers to Tamboran Resources Corporation, a Delaware corporation.

"TB1" refers to Tamboran (B1) Pty Ltd, an Australian private limited company, which is a 50 / 50 joint venture between us and Daly Waters that holds a 77.5% working interest in the Beetaloo Joint Venture through its wholly owned subsidiary, TB1 Operator.

"*TB1 Operator*" refers to Tamboran B2 Pty Ltd, an Australian private limited company.

"*TR Ltd.*" refers to Tamboran Resources Pty Ltd (f/k/a Tamboran Resources Limited), an Australian private limited company and wholly owned subsidiary of Tamboran following the Corporate Reorganization.

"*TR West*" refers to Tamboran (West) Pty Ltd, an Australian private limited company.

"*unconventional drilling*" refers to the application of advanced technology, other than traditional vertical well extraction, to extract oil and natural gas resources. Unconventional drilling typically includes directional drilling across long, lateral intervals within narrow horizontal formations offering greater contact area with the producing formation, and various types of hydraulic fracturing at multiple stages to optimize production.

"*unconventional natural gas*" refers to natural gas that cannot be produced at economic flow rates nor in economic volumes unless the well is stimulated by a hydraulic fracture treatment, a horizontal wellbore, or by using multilateral wellbores or some other technique to expose more of the reservoir to the wellbore.

"*unconventional play*" refers to a set of known or postulated oil and or natural gas resources or reserves warranting further exploration which are extracted from (a) low-permeability sandstone and shale formations and (b) coalbed methane. These plays require the application of unconventional drilling to extract the oil and natural gas resources.

"unconventional resources" refers to the umbrella term for oil and natural gas that is produced by means that do not meet the criteria for conventional production. What has qualified as "unconventional" at any particular time is a complex function of resource characteristics, the available exploration and production technologies, the economic environment, and the scale, frequency and duration of production from the resource. The term is most commonly used in reference to oil and gas resources whose porosity, permeability, fluid trapping mechanism, or other characteristics differ from conventional sandstone and carbonate reservoirs. Coalbed methane, gas hydrates, shale gas, shale oil, fractured reservoirs and tight gas sands are considered unconventional resources.

"undeveloped acre" refers to acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of crude oil, NGLs, and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acres include net acres held by operations until a productive well is established in the spacing unit.

"*unproved properties*" refers to properties with no proved reserves.

"*working interest*" refers to the right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Trademarks and Trade Names

This report contains, and incorporates by reference, references to trademarks, service marks and trade names belonging to us or other entities. All trademarks, service marks and trade names included or incorporated by reference into this report are the property of their respective owners. Solely for convenience, trademarks and trade names referred to in this report or the documents incorporated by reference herein, including logos, artwork and other visual displays, may appear without the ® or ™ symbols, but such references are not intended to indicate, in any way, that the respective owners will not assert, to the fullest extent under applicable law, their rights thereto. We do not intend our use or display of other companies' trade names, trademarks or service marks to imply a relationship with, or endorsement or sponsorship of us by, any other companies.

Cautionary Note Regarding Industry and Market Data

This report includes information concerning our industry and the markets in which we will operate that is based on information from various sources including public filings, internal company sources, various third-party sources and management estimates. Our management estimates regarding our position, share and industry size are derived from publicly available information and its internal research, and are based on a number of key assumptions made upon reviewing such data and our knowledge of such industry and markets, which we believe to be reasonable. While we believe the industry, market and competitive position data included in this report is reliable and is based on reasonable assumptions, such data is necessarily subject to a high degree of uncertainty and risk and is subject to change due to a variety of factors, including those described in "Cautionary Note Regarding Forward-Looking Statements," "Summary Risk Factors," "Risk Factors" and elsewhere in this report. These and other factors could cause results to differ materially from those expressed in the estimates included herein. We have not independently verified any data obtained from third-party sources and cannot assure you of the accuracy or completeness of such data.

Presentation of Financial and Operating Data

Our fiscal year ends on June 30. Unless otherwise noted, any reference to a year preceded by the words "fiscal year" refers to the twelve months ended June 30 of that year. For example, references to "fiscal year 2024" refer to the twelve months ended June 30, 2024. References to "dollars," "$," "U.S. dollars" and "US$" refer to United States dollars; and references to "Australian dollars" and "A$" refer to Australian dollars.

Tamboran was incorporated on October 3, 2023 and does not have financial operating results prior to the Corporate Reorganization effective December 13, 2023. As a result of the Corporate Reorganization, Tamboran became the parent company of TR Ltd., and for financial reporting purposes, the financial statements of TR Ltd. became the financial statements of Tamboran. As a result of the Corporate Reorganization, Tamboran issued to eligible shareholders of TR Ltd. one CDI of its common stock for every one ordinary share of TR Ltd., with each CDI representing 1/200th of a share of Tamboran's common stock. Our historical financial statements in this report are presented as though the Corporate Reorganization had taken place on July 1, 2021 and Tamboran had existed as the parent of TR Ltd. as of that date. All share and per share data presented in this report have been retroactively adjusted to reflect a one for two hundred (1:200) exchange ratio and all options over ordinary shares in the predecessor have been retroactively presented as options over CDIs in Tamboran. See "*Business and Properties—General Development of Business and Corporate Reorganization*."

Rounding and Percentages

The financial information and certain other information presented in this report have been rounded to the nearest whole number or the nearest decimal. Therefore, the sum of the numbers in a column may not conform exactly to the total figure given for that column in certain tables in this report. In addition, certain percentages presented in this report reflect calculations based upon the underlying information prior to rounding and, accordingly, may not conform exactly to the percentages that would be derived if the relevant calculations were based upon the rounded numbers or may not sum due to rounding.

Currency Exchange Rate Data

Our functional currency is the Australian dollar, and our consolidated financial statements are presented in the U.S. dollar. The functional currency is the currency of the primary economic environment in which an entity's operations are conducted. We translate our consolidated financial statements into the presentation currency using exchange rates in effect on the relevant balance sheet date for assets and liabilities and average exchange rates for the period for statement of operations accounts, with the difference recognized as a separate component of stockholders' equity.

The following exchange rates were used to translate our consolidated financial statements and other financial and operational data shown in constant currency:

	Average for the Fiscal Year	
	2024	**2023**
A$1.00	$0.66	$0.67

Cautionary Note Regarding Emerging Growth Company Status

Section 102(b)(1) of the Jumpstart Our Business Startups Act ("JOBS Act") exempts emerging growth companies from being required to comply with new or revised financial accounting standards until private companies (that is, those that have not had a Securities Act registration statement declared effective or do not have a class of securities registered under the Exchange Act) are required to comply with the new or revised financial accounting standards. The JOBS Act provides that a company can elect to opt out of the extended transition period and comply with the requirements that apply to non-emerging growth companies but any such election to opt out is irrevocable. We have elected not to opt out of such extended transition period which means that when a standard is issued or revised and it has different application dates for public or private companies, we, as an emerging growth company, can adopt the new or revised standard at the time private companies adopt the new or revised standard, until such time we are no longer considered to be an emerging growth company. At times, we may elect to adopt a new or revised standard early.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains “forward-looking statements” within the meaning of the safe harbor provisions of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements are neither historical facts nor assurances of future performance. Instead, they are based only on our current beliefs, expectations and assumptions regarding the future of our business, future plans and strategies, projections, anticipated events and trends, the economy and other future conditions. Forward-looking statements can be identified by words such as: “anticipate,” “intend,” “plan,” “goal,” “commit,” “seek,” “believe,” “project,” “estimate,” “expect,” “strategy,” “future,” “likely,” “may,” “should,” “will” and similar references to future periods.

It is possible that the Company’s future financial performance may differ from expectations due to a variety of factors, including but not limited to: our early stage of development with no material revenue expected until 2026 and our limited operating history; the substantial additional capital required for our business plan, which we may be unable to raise on acceptable terms; our strategy to deliver natural gas to the Australian East Coast and select Asian markets being contingent upon constructing additional pipeline capacity, which may not be secured; the absence of proved reserves and the risk that our drilling may not yield natural gas in commercial quantities or quality; the speculative nature of drilling activities, which involve significant costs and may not result in discoveries or additions to our future production or reserves; the challenges associated with importing U.S. practices and technology to the Northern Territory, which could affect our operations and growth due to limited local experience; the critical need for timely access to appropriate equipment and infrastructure, which may impact our market access and business plan execution; the operational complexities and inherent risks of drilling, completions, workover, and hydraulic fracturing operations that could adversely affect our business; the volatility of natural gas prices and its potential adverse effect on our financial condition and operations; the risks of construction delays, cost overruns, and negative effects on our financial and operational performance associated with midstream projects; the potential fundamental impact on our business if our assessments of the Beetaloo are materially inaccurate; the concentration of all our assets and operations in the Beetaloo, making us susceptible to region-specific risks; the substantial doubt raised by our recurring operational losses, negative cash flows, and cumulative net losses about our ability to continue as a going concern; complex laws and regulations that could affect our operational costs and feasibility or lead to significant liabilities; community opposition that could result in costly delays and impede our ability to obtain necessary government approvals; exploration and development activities in the Beetaloo that may lead to legal disputes, operational disruptions, and reputational damage due to native title and heritage issues; the requirement to produce natural gas on a Scope 1 net zero basis upon commencement of commercial production, with internal goals for operational net zero, which may increase our production costs; the increased attention to ESG matters and environmental conservation measures that could adversely impact our business operations; risks related to our corporate structure; risks related to our common stock and CDIs; and the other risk factors discussed in the this report and the Company’s filings with the Securities and Exchange Commission (the “SEC”).

It is not possible to foresee or identify all such factors. Any forward-looking statements in this report are based on certain assumptions and analyses made by the Company in light of its experience and perception of historical trends, current conditions, expected future developments, and other factors it believes are appropriate in the circumstances. Forward-looking statements are not a guarantee of future performance and actual results or developments may differ materially from expectations. While the Company continually reviews trends and uncertainties affecting the Company’s results of operations and financial condition, the Company does not assume any obligation to update or supplement any particular forward-looking statements contained in this report, except as required by law.

Additionally, certain forward-looking and other statements in this Annual Report on Form 10-K or other locations, such as the Company’s corporate website, regarding ESG matters are informed by various ESG standards and frameworks (which may include standards for the measurement of underlying data) and the interests of various stakeholders. Accordingly, such information may not be, and should not be interpreted as necessarily being “material” under the federal securities laws for SEC reporting purposes, even if the Company uses the word “material” or “materiality” in such discussions. ESG information is also often reliant on third-party information or methodologies that are subject to evolving expectations and best practices, and the Company’s approach to and discussion of these matters may continue to evolve as well. For example, the Company’s disclosures may change due to revisions in framework requirements, availability of information, changes in its business or applicable governmental policies, or other factors, some of which may be beyond its control.

SUMMARY RISK FACTORS

The following is a summary of the material risks and uncertainties we have identified, which should be read in conjunction with the more detailed description of each risk factor contained below.

Risks Related to Our Business and Industry

- We are an early stage development company with no material revenue expected until 2026, at the earliest. We have a limited operating history, and our future performance is uncertain. Our ability to successfully drill and complete the wells identified for our current capital plan will depend on a variety of factors;
- Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms in the future, or at all, which may in turn limit our ability to execute on our plans;
- Our business plan contemplates delivering natural gas to the Northern Territory, the Australian East Coast, as well as select markets in South and East Asia. Our ability to deliver natural gas in significant quantities to these markets depends on the construction of additional pipeline capacity. We cannot assure you that we will be able to secure sufficient take-away capacity on our timing or at all;
- We have no proved reserves at this time and areas that we decide to drill may not yield natural gas in commercial quantities or quality, or at all;
- Drilling wells is speculative, often involving significant costs that may be more than our estimates, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business;
- We intend to import and implement U.S. practices and technology for use in the development of our properties in the Northern Territory. There is limited experience with these practices and technology within the workforce in the areas we operate. The ability to attract and train a qualified workforce could hamper our present operations and limit our ability to grow;
- Our inability to access appropriate equipment and infrastructure in a timely manner may hinder our access to natural gas markets and delay the phases of our business plan;
- Drilling, completions, workover and hydraulic fracturing operations are operationally complex activities which present certain risks that could adversely affect our business, financial condition or results of operations;
- Natural gas prices are volatile. A reduction or sustained decline in prices may adversely affect our business, financial condition or results of operations and our ability to meet our financial commitments or raise capital;
- Construction of midstream projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our financial condition, results of operations, cash flows and liquidity;
- If our assessments of the Beetaloo are materially inaccurate, it will have a fundamental impact on our business;
- All of our assets and operations are located in the Beetaloo, making us vulnerable to risks associated with operating in one geographic area; and
- Our recurring losses from operations, negative cash flows and substantial cumulative net losses raise substantial doubt about our ability to continue as a going concern.

Risks Related to Environmental, Legal Compliance and Regulatory Matters

- We are subject to complex federal, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities;

- We face community opposition from certain parties with respect to our development of the Beetaloo and related operations, which could result in significant costs and delays and could impede our ability to obtain the government approvals required for such operations;
- The exploration and development of natural gas in the Beetaloo can pose native title and heritage risks, potentially leading to legal disputes, operational disruptions, and reputational damage;
- Upon commencement of commercial production, we are required by the Australian government to produce natural gas in the Beetaloo on a Scope 1 net zero basis. We also have set an internal goal of producing natural gas with net zero equity Scope 1 and 2 emissions. Meeting these requirements and goals may increase our costs of production, and we may be unable to meet these requirements and goals; and
- Increased attention to ESG matters and environmental conservation measures may adversely impact our business.

Risks Related to our Corporate Structure

- We are a holding company. Our sole material asset is our equity interest in TR Ltd. and we will be accordingly dependent upon distributions from TR Ltd. to pay taxes and cover our corporate and other overhead expenses.

Risks Related to our Common Stock and our CDIs

- The requirements of being a public company, including compliance with the reporting requirements of the ASX listing rules and the Exchange Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner;
- Changes in foreign currency exchange rates could materially adversely affect our business, results of operations or financial condition;
- We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders' best interests;
- We have identified a material weakness in our internal control over financial reporting. Any material weakness may cause us to fail to timely and accurately report our financial results or result in a material misstatement of our financial statements;
- The different characteristics of the capital markets in Australia and the United States may negatively affect the trading prices of our CDIs and common stock, and may limit our ability to take certain actions typically performed by a U.S. company;
- Our ability to raise additional capital may be significantly limited by listing rules of the ASX that limit the amount of common stock that we are permitted to issue without stockholder approval; and
- As a result of listing CDIs on the ASX, we are subject to the listing rules of the ASX, which may strain our resources, divert management's attention and affect our ability to manage our business or raise additional capital.

PART I

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

General Development of Business and Corporate Reorganization

Headquartered in Sydney, Australia, we have been engaged in the development of Australian oil and natural gas reserves since our formation in 2009. Since 2014, we have focused our development activities within the Northern Territory.

TR Ltd. completed its initial public offering in Australia in July 2021 and was publicly listed on the ASX under the ticker "TBN." Tamboran was incorporated in Delaware on October 3, 2023 for the purpose of effecting a scheme of arrangement under Australian law between Tamboran and TR Ltd., which we refer to as the "Corporate Reorganization." On December 13, 2023, Tamboran implemented the Corporate Reorganization and acquired all of the outstanding ordinary shares of TR Ltd. in exchange for 1,716,672,600 CDIs representing beneficial interests in 8,583,363 shares of our common stock, with each CDI representing 1/200th of a share of our common stock. Concurrently, TR Ltd.'s ordinary shares were delisted from the ASX, and our CDIs were listed on the ASX. Following the Corporate Reorganization, Tamboran's assets consisted primarily of 100% of the ordinary shares of TR Ltd. Tamboran completed its U.S. initial public offering ("IPO") in July 2024.

The description of our business included in this report as of the dates and for the periods prior to the Corporate Reorganization reflect the business of TR Ltd., and the description of our business as of the dates and for the periods from and after the Corporate Reorganization reflect the business of Tamboran and its consolidated subsidiaries, in each case unless otherwise expressly stated or the context otherwise requires. The consolidated financial statements and other financial information of Tamboran included in this report reflect the historical financial statements of TR Ltd., as retroactively adjusted to give effect to the Corporate Reorganization.

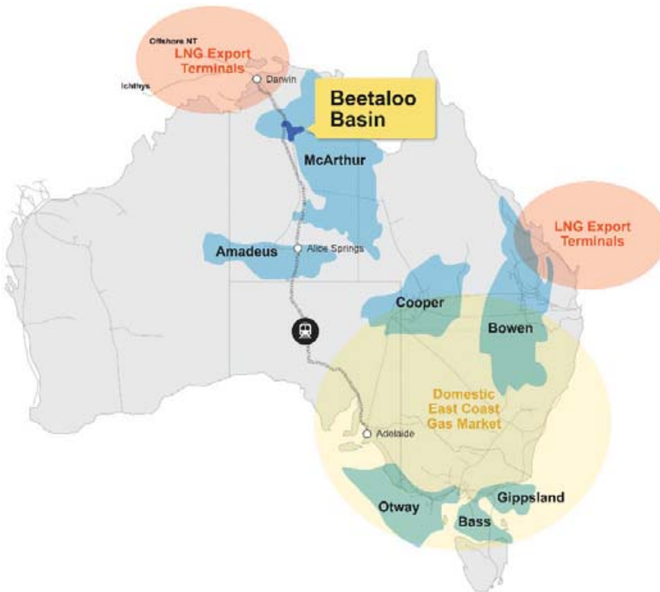
The terms "we," "us," "our" and the "Company," as used herein and unless otherwise stated or indicated by context, refer to TR Ltd. and its subsidiaries prior to the Corporate Reorganization and to Tamboran and its subsidiaries after the Corporate Reorganization.

Overview

Tamboran is an early stage, growth-driven independent natural gas exploration and production company focused on an integrated approach to the commercial development of the natural gas resources in the Beetaloo Basin located within the Northern Territory of Australia. We and our working interest partners have exploration permits ("EPs") to approximately 4.7 million contiguous gross acres (approximately 1.9 million net acres to Tamboran) and are currently the largest acreage holder in the Beetaloo. We believe natural gas will play a significant role in the transition to cleaner energy and are committed to supporting the global energy transition by developing commercial production of natural gas in the Beetaloo with net zero equity Scope 1 and 2 emissions.

The Beetaloo

The Beetaloo, an area of approximately seven million acres (10,800 square miles), is believed to contain significant quantities of unconventional natural gas resources. The Beetaloo is a structural component of the Greater McArthur Basin in the Northern Territory and is located approximately 300 miles southeast of Darwin, Northern Territory. The following image illustrates the location of the Beetaloo:



Preliminary results and third-party data indicate that natural gas produced in the Beetaloo generally has lower carbon dioxide content compared to natural gas produced elsewhere in Northern Australia and major fields supplying Australia's East Coast gas market. We believe our application of U.S. drilling and completion technology will provide us with a competitive advantage to achieve natural gas production in compliance with the Australian government's recently enacted GHG regulations. The Australian government's current policy is to target net zero carbon emissions economy-wide by 2050. Additionally, the Australian government requires all shale gas production in the Beetaloo following commercialization to be conducted on a Scope 1 net zero emissions basis. We have set a target to exceed these requirements by reaching net zero equity Scope 1 and 2 GHG emissions upon commencement of commercial production. We expect there to be a variety of means in which we could achieve our operational net zero goals, including but not limited to, utilizing carbon offsets, for which the prices are capped by applicable law, exploring opportunities to power our facilities with renewable energy sources, implementing methane leakage minimization technology in the design and operation of our production facilities and integrating a carbon capture storage hub with our proposed LNG project.

To date, our appraisal and development activities have focused on the dry gas shale target of the Middle Velkerri B formation, although we expect to eventually evaluate other benches for future development. Regional data from exploration wells, initial results from our appraisal wells, including well log and core data, as well as available 2-D seismic data, indicate that the geological properties of the Middle Velkerri section in the Beetaloo are widespread with geology similar to that of the Marcellus Shale of the Appalachian Basin in the northeastern United States (the "Marcellus"). In particular, the dry gas areas of the Marcellus qualify as an appropriate analogous reservoir to the Middle Velkerri shale of the Beetaloo, having similar rock and fluid properties (such as organic-rich source rock and similar thermal maturity), similar reservoir conditions (including depth, pressure gradient and temperature ranges), and drive mechanism (using pressure depletion and gas desorption). While the Marcellus is at a more advanced stage of development than the Beetaloo, we believe comparison to the Marcellus may assist in our estimations and interpretation of data.

Our Business Plan

Our business plan consists of three distinct phases in the development of the Beetaloo. The focus of the first phase will be on the transition from exploration activities to the commercialization of our Beetaloo properties. Further to that goal, we expect to:

- drill and complete an additional two wells in 2024,
- four wells in 2025,
- progress a project to design and construct the 40 MMcf/d compression and dehydration plant (the "Sturt Plateau Compression Facility" or "SPCF"), and
- progress a 20-mile pipeline to the existing gas pipeline network (collectively, the "Shenandoah South Pilot Project").

Our goal is to achieve ~40 MMcf/d (gross) plateau production commencing in 1H 2026 from the Shenandoah South Pilot Project. Based on our petrophysical analysis from completed appraisal wells, we have already identified what we believe to be the most productive acreage and shale benches to target for our first stage wells.

We have early development agreements with APA Group (ASX: APA), Australia's largest gas infrastructure company by volume whereby APA has committed to the study and planning of a project to build, own, and operate a new 20-mile pipeline to connect our wells to the existing gas transmission network through the Amadeus Gas Pipeline ("AGP"). Tamboran is progressing the SPCF that would upgrade the raw gas to meet sales gas quality, subject to the terms of definitive development agreements.

We estimate the remaining capital required to deliver the first development phase to production will be approximately \$110 million (A\$170 million) to \$140 million (A\$220 million) net to Tamboran (refer to table below).

A$ millions	**Low**	**High**
Drilling and completions	100	120
SPCF[1]	20	30
Related pad construction	20	30
Corporate G&A	30	40
Total [2]	**170**	**220**

(1) Compression facility expenditure assumes new infrastructure partner. Tamboran is evaluating the opportunity to sell interest in the midstream infrastructure asset, with future gas to be tolled via the new third-party infrastructure.

(2) Excludes capital spend on assets outside the Pilot Project area.

We intend to fund these costs with cash on hand as well as net cash proceeds from one or more debt or equity offerings. We currently expect gas sales to commence from our wells in the first half of 2026. Through the course of the completion of the additional six wells, we believe we can reduce costs through greater efficiency while simultaneously providing us with sufficient data to confirm the EUR for wells drilled in the Beetaloo. Our development plan seeks to efficiently drill from pad wells, utilizing long laterals and modern completion techniques employed by U.S. onshore operators. We expect the cost structure and production profiles achieved with our initial wells to lead to a financial investment decision for an initial large scale drilling program in our second phase.

The second phase of our business plan involves building our drilling program to produce natural gas to supply the Australian East Coast and Northern Territory markets. The existing pipeline infrastructure, the AGP in the Northern Territory, can export ~50 MMcf/d northbound and ~50 MMcf/d to the East Coast. We have early development agreements with APA whereby APA has committed to the study and planning of a project to construct, own, and operate an approximately 1,000-mile pipeline to connect the Beetaloo to the main trunk line of the East Coast Gas Grid. We anticipate that this pipeline will reduce the cost of transporting gas from the Northern Territory to the East Coast by up to 50%. We have non-binding letters of intent from six of Australia's largest energy retailers with respect to the purchase of natural gas from us, with an aggregate volume of 875 MMcf/d for a period of up to 10 to 15 years.

In the third phase of our business plan, following commercialization of the Beetaloo, we intend to drill additional wells with the intent to supply natural gas for export through the existing liquified natural gas ("LNG") plants in the Middle Arm Sustainable Development precinct ("MASD") Darwin and our proposed 6.6 Mtpa Northern Territory LNG export facility ("NTLNG") to South and East Asian markets. Depending on the volume of unused capacity available at existing LNG plants in the MASD Darwin, this phase may occur before or in parallel with the second phase. In consideration of our proposed NTLNG project, the government of the Northern Territory of Australia has awarded us exclusive use of an approximately 420-acre site for a term extending to December 31, 2027 under the Interim Agreement, with two one-year extension options to progress pre-FEED and FEED studies with respect to NTLNG. We completed the Concept Select study in the first quarter of 2024 with Wood Group, which affirmed the feasibility of commencement of commissioning of the first LNG train in 2030. In August 2024, we awarded the EPC contract for pre-FEED activities to Bechtel, the world's leading LNG EPC contractor. Pre-FEED activities are expected to be completed in 1H 2025.

The MASD, an industrial complex adjacent to the city of Darwin, seeks to provide infrastructure focused on low emissions operations, for the export, processing, storage, shipping and rail transportation of LNG and other hydrocarbons. The MASD precinct is currently home to an export hub with two existing and operational LNG export terminals, the Darwin LNG terminal with a capacity of 3.7 Mtpa and the Ichthys LNG terminal with a capacity of 8.9 Mtpa. The Australian government has committed A$1.5 billion in investments commencing in 2025 to further develop MASD infrastructure and access, including dredging of the deepwater port, construction of road and rail access and distribution of electricity. We estimate total time required for construction of the NTLNG project to be between three to five years and have a non-binding memorandum of understanding with each of BP Singapore Pte. Ltd ("bp") and Shell Eastern Trading (Pte) Ltd ("Shell") for 20-year LNG purchase contracts. We intend to seek additional strategic partners for the financing and development of these and other infrastructure projects.

Our business and development plans include the continuous focus on reducing costs while increasing production efficiencies. We believe that importing U.S. unconventional drilling and completion techniques, best-practices and technology, together with the right personnel, will reduce the incremental cost to drill and complete each subsequent well. We currently have on contract with Helmerich and Payne, Inc. (NYSE: HP), one H&P FlexRig® with a 10-year option to contract for up to five additional rigs. We have entered into a two-year preferred arrangement with Liberty Energy Inc. (NYSE: LBRT) ("Liberty Energy") to provide us dedicated frac fleets and personnel on market terms (as reasonably determined by the Beetaloo Joint Venture).

We estimate the drilling and completion costs of each of the remainder of our initial six wells will average approximately $28 million (gross) as a result of our application of U.S. practices, longer lateral lengths and increased number of stimulated stages. We are targeting long-term development well costs of $16 million per well with horizontal sections of more than 10,000 feet with 60 stages. We believe by taking advantage of efficiencies related to economies of scale, continued infrastructure development in the Beetaloo and resource maturation, over time we will significantly reduce the cost to drill and complete our wells.

Competitive Strengths

We have a number of strengths that we believe will help us successfully execute our business strategy, including:

- **Leading acreage holder and operator in the high-quality Beetaloo**. Our Beetaloo assets cover approximately 4.7 million contiguous gross acres (approximately 1.9 million net acres), the most extensive position currently reported in the Beetaloo. Over 5,000 miles of 2-D seismic data has been collected over the Beetaloo. Based on our seismic we believe our acreage position consists of significant quantities of high-quality natural gas resources in what we believe to be the core of the Velkerri shale gas play. Our initial development area of the Middle Velkerri-B shale shows an average shale thickness of 230 feet across approximately 610,400-acres (approximately 950 square miles). We estimate the Middle Velkerri section to be continuous across the same area. The Beetaloo has very few operators and no urban areas. The geographical features of the Beetaloo, our expansive contiguous acreage position and very few restrictive boundaries support more than 10,000-foot laterals and U.S. style unconventional drilling techniques. In addition, we believe our position as the leading acreage holder in the Beetaloo will support our efforts to establish commercial production in volumes sufficient to stimulate investment in in-basin frac sand and other services.
- **Premium Markets**. We expect the relative geographic proximity of the Beetaloo to the major population centers on the Australian East Coast and the Asian LNG markets to provide us the opportunity to potentially obtain attractive prices for our natural gas relative to markets in North America based on historical pricing. For example, during the calendar year 2024 to date, spot prices for natural gas delivered from Henry Hub averaged $2.20 per MMBtu. Over that same period, the Japan Korea Marker ("JKM") continuous futures price of LNG averaged $11.23 per MMBtu. Although production costs in the Beetaloo are currently significantly higher than U.S. onshore operations, upon full commercialization of the Beetaloo, we expect those costs to decline.
- **High caliber and experienced management team with a track record of success**. Our senior management team has extensive experience with vertical and horizontal drilling in unconventional plays and an average of over 25 years of experience in the upstream oil and gas industry. Additionally, our leadership team has significant experience managing integrated energy and power assets for large-scale enterprises, including companies such as Unocal, Chevron, Apache, and ExxonMobil. Joel Riddle, our CEO since 2013, has more than 25 years of experience in the upstream oil and gas industry, and Faron Thibodeaux, our COO, has over 40 years of technical and operations experience in the energy industry. Our board of directors includes our Chairman Dick Stoneburner, the former co-founder, President and Chief Operating Officer of Petrohawk Energy Corporation and President – North America Shale Production Division for BHP Billiton Petroleum, a subsidiary of BHP Group Ltd. (NYSE: BHP), and Fredrick Barrett, co-founder and former CEO of Bill Barrett Corporation, each of whom have more than 35 years of experience raising capital and operating assets in the oil and gas industry.
- **Operational Net Zero**. Australian law requires that natural gas reserves in the Beetaloo be produced on a Scope 1 net zero basis upon achieving commercial production. We believe we are positioned to achieve net zero equity Scope 1 and Scope 2 emissions (i.e. "operational net zero"). We have a comprehensive sustainability program, which is overseen and directed by a Sustainability Committee composed of board members. We believe natural gas delivered from the Beetaloo will provide an attractive alternative for domestic and Asian economies seeking to reduce reliance on coal and reduce their own GHG emissions.
- **High quality, blue-chip strategic partners**. We have contracted H&P to exclusively provide drilling services for our wells in the Beetaloo. We have an agreement with Liberty Energy to provide a dedicated frac fleet and personnel. We are working with APA Group to progress access and approvals for a large diameter gas pipeline from the Beetaloo Basin to the Australian East Coast gas grid. In parallel we are working on a pipeline from the Beetaloo Basin to Darwin to deliver gas to our proposed

NTLNG facility. Our memoranda of understanding with each of bp and Shell contemplate 20-year LNG purchase agreements from our proposed NTLNG development. We have entered into a gas sales agreement with the Northern Territory Government ("NT Government") for gas sales of up to ~40 MMcf/d for a period of up to 15.5 years. We also have non-binding letters of intent from six of Australia's largest energy retailers with respect to the purchase of natural gas from us, with an aggregate volume of 875 MMcf/d for a period of up to 10 to 15 years. We are seeking to enter into definitive agreements with these strategic partners as we execute on subsequent phases of our business plan, and we will continue to seek additional strategic partnerships in the development of the Beetaloo. See "*—Agreements Relating to the Development of our Assets*" in this report and "*Certain Relationships and Related Person Transactions*" included in the 2024 Proxy Statement for further information.

Business Strategies

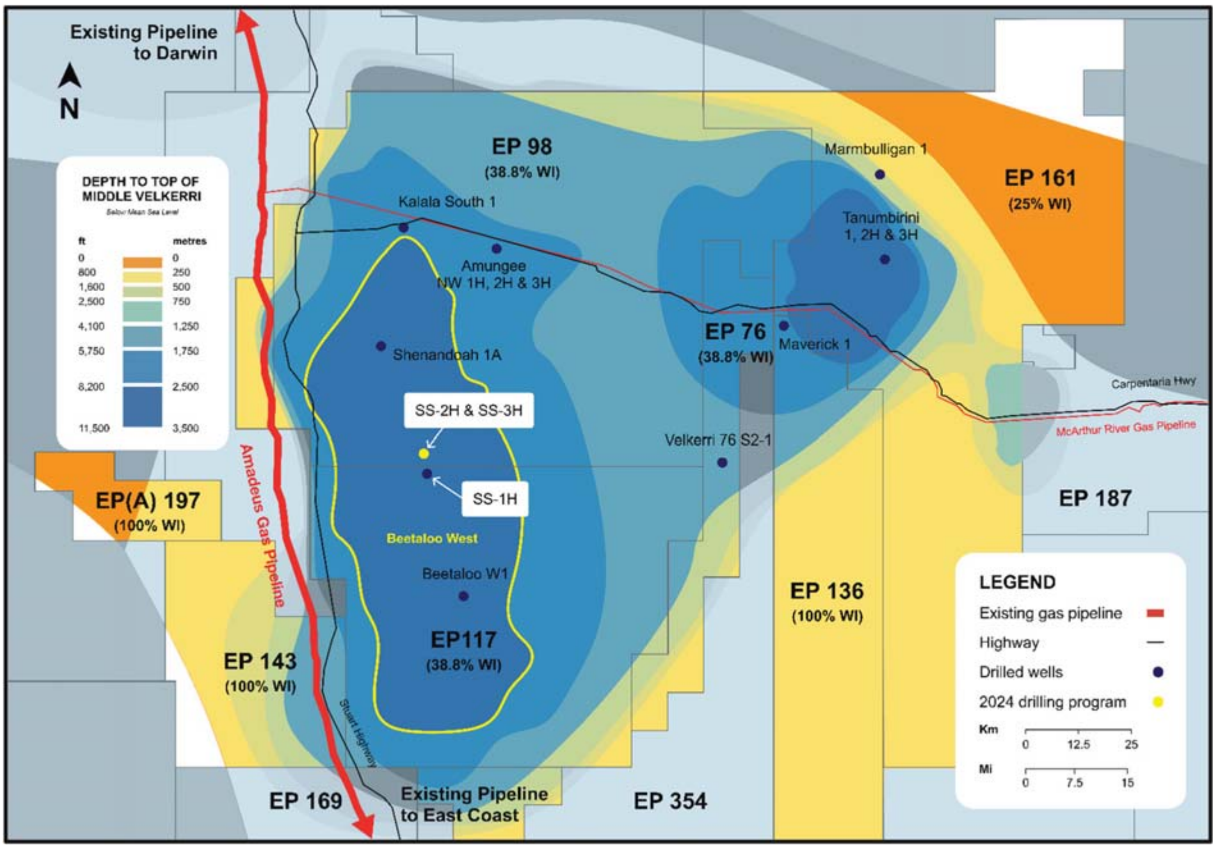
We intend to execute the following business strategies:

- **Commercialize our resources in the Beetaloo**. We intend to commercialize our natural gas resources in the Beetaloo over the next two to three years. Leveraging the experience and data derived from our initial well program, we anticipate commencing a multi-year drilling program as early as 2026, subject to our ability to obtain the necessary capital and completion of certain third-party infrastructure projects, including the proposed pipelines with APA Group.
- **Pursue an integrated approach to the development and scale of natural gas production and transportation projects**. We aim to build additional infrastructure with partners to support the take-away of up to 2.0 Bcf/d of gross production following the initial commercialization of the Beetaloo. Adjacent to the Beetaloo are currently two natural gas pipelines, one running north to Darwin and another pipeline to the Australian East Coast. We are in discussion with APA Group with respect to the construction of a larger diameter pipeline to the Australian East Coast, and we anticipate commencing construction of our NTLNG project as early as 2027, subject to receiving the necessary approvals. Additionally, there are two LNG export terminals in operation near Darwin through which we can eventually sell additional production, subject to capacity constraints.
- **Import U.S. best practices to become a low-cost provider of natural gas to the Australian domestic market and regional Asian markets**. We will continue to import best practices from the U.S. E&P industry to enhance production and reserve recovery per well while simultaneously reducing capital and operating costs. To date, horizontal drilling and completion techniques and pad drilling have not been widely used in the Australian E&P industry. Based on analysis of our preliminary results and seismic data, we believe the geology of the Beetaloo is conducive to U.S.-style unconventional drilling, and we have entered into an agreement with H&P to bring U.S. unconventional drilling rigs to the Beetaloo. We currently have on contract an H&P FlexRig®, which is currently operational within the Beetaloo, with an option to contract for additional rigs. We have an agreement with Liberty Energy to provide a dedicated frac fleet and personnel, which is currently being mobilized to the Beetaloo.
- **Lower Emissions from Natural Gas Production.** As discussed above, we aim to achieve operational net zero from natural gas production. We intend to participate in an open-access, multi-user carbon capture utilization and sequestration project at the proposed NTLNG facility and will seek to power our gathering and processing facilities from renewable sources, including solar and wind, to the extent available. Our goal is to deliver LNG to global markets from net zero equity Scope 1 and 2 operations in an effort to replace coal consumption, particularly in Australian and East Asian markets, with lower-emissions natural gas from the Beetaloo.

Our Assets and Operations

We currently hold interests in six EPs and one EP(A), all of which are contiguous to one another and located in the Beetaloo. See "*—Title to Properties*" for further information. Our key assets are (i) a 25% non-operated working interest in EP 161, (ii) a 38.75% working interest in EPs 76, 98 and 117, where we are the operator, and (iii) a 100% working interest in EPs 136, 143 and EP(A) 197, where we are the operator. The deepest portions of the Beetaloo, and our strategic near-term focus are those areas covered by EPs 76, 98, and 117, which are held indirectly through TB1, a 50/50 joint venture with Daly Waters, an entity controlled by Bryan Sheffield. TB1 holds interests in EPs covering four million gross (1.5 million net) acres. See "*—Agreements Relating to the Development of our Assets —TB1 Joint Venture Agreement*" for a description of the material terms of the TB1 Joint Venture Agreement.

Our assets are depicted by the colored areas in the map of the Beetaloo below, with the deepest "core" regions of the Beetaloo (the darker blues) in the west being the focus of our development:



Summarized below are our interests, as of June 30, 2024, in exploration permits in Beetaloo Basin together with the wells drilled on such acreage and our associated net working interest. We consider all of our acreage as undeveloped, since even though we classify one of our appraisal wells as "productive," acreage has not been allocated or assigned to such well. Our contiguous acreage position and the scarcity of other operators or urban areas near the Beetaloo provide us with the space necessary to eventually drill pad wells with up to three to four-mile horizontal laterals, greatly increasing efficiencies and production from a relatively smaller number of wells.

Exploration Permit	Gross / Net Acres	Expiration Date
EP 76	346,700 / 134,346	May 30, 2028
EP 98	2,312,262 / 896,000	May 30, 2028
EP 117	1,380,864 / 535,085	May 30, 2028
EP 136	207,000 / 207,000	July 23, 2029
EP 143	512,000 / 512,000	March 4, 2028
EP 161	512,000 / 128,000	March 20, 2026
EP(A) 197	192,000 / 192,000	N/A

As of June 30, 2024, we have participated in six appraisal wells since fiscal year 2021, four of which we drilled as the operator:

Well, Name[1]	Operator	Non-Operator(s)	Permit	Date Drilled	Tamboran Working Interest
Tanumbirini #2 (“T2H”)	Santos	Tamboran	161	May 2021	25%
Tanumbirini #3 (“T3H”)	Santos	Tamboran	161	Aug 2021	25%
Maverick 1V (“M1V”)	Tamboran	N/A	136	Aug 2022	100%
Amungee NW-2H (“A2H”)	Tamboran	DWE & FOG	98	Nov 2022	38.75%
Shenandoah South 1H (“SS1H”)	Tamboran	DWE & FOG	117	Aug 2023	38.75%
Amungee NW 3H (“A3H”)	Tamboran	DWE & FOG	98	Sept 2023	38.75%

(1) Our interests in the A2H, SS1H and A3H are held through a joint venture with DWE, which holds an undivided 77.5% working interest.

As of June 30, 2024, we operate four gross (approximately 2.2 net) natural gas wells (the SS1H, A2H, A3H, and MIV wells) and hold interests in an additional two gross (approximately 0.5 net) non-operated wells (the T2H and T3H wells). Although none of the wells drilled in the Beetaloo to date are currently flowing to sales, we successfully completed flow testing of our SS1H well and believe it is currently productive. We believe the T2H, T3H, and A2H wells are likely capable of producing sufficient quantities of gas to justify completion or recompletion at a future date with further investment and workover. Our A3H well is capable of being stimulated but is currently drilled but uncompleted. As of June 30, 2024, no additional wells were undergoing or awaiting completion.

In early July 2023, H&P’s FlexRig® that was imported into Australia and successfully mobilized to the SS1H well location targeting the deeper Middle Velkerri B Shale in EP 117. We commenced drilling of the SS1H well in early August 2023 and intersected a 295-foot interval of Middle Velkerri B Shale, the thickest section intersected in the Beetaloo depocenter to date. In February 2024, SS1H delivered an IP30 flow rate of 3.2 MMcf/d over the 1,644-foot, 10-stage stimulated length within the Middle Velkerri B Shale, an IP60 flow rate of 3.0 MMcf/d, and an IP90 flow rate of 2.9 MMcf/d. Normalizing the production rate for a 10,000-foot horizontal lateral, the IP30 flow rate in SS1H would have been approximately 19.5 MMcf/d, the IP60 flow rate would have been approximately 18.4 MMcf/d, and the IP90 flow rate would have been approximately 17.8 MMcf/d.

Also in July 2023, we completed analysis of the T2H and T3H flow tests. The productivity of the wells, which flow tested the Middle Velkerri B Shale at depths of more than 11,000 feet total vertical depth, exhibited higher flowing tubing pressures, thus continuing to validate our internal view that the “core” deeper areas of the Beetaloo will be more productive and validate further evaluation. Our T2H and T3H well were drilled with low intensity, shorter lateral lengths (approximately 2,000 feet).

In September 2023, we commenced drilling of the A3H well from the same well pad as the A2H well to follow up earlier drilling results. The well was successfully drilled in less than 18 days, the fastest well drilled with a horizontal section in the Beetaloo to date. The activities were completed 20 days faster than the shallower A2H well and approximately 30% lower cost, demonstrating the increased drilling efficiency of the H&P FlexRig®. The A3H well is capable of being stimulated but is currently drilled and uncompleted.

On March 4, 2024, Falcon, the owner of the remaining 22.5% interest in the Beetaloo Joint Venture’s assets, capped its participation to 5% in the second Shenandoah South well pad (“SS2”) and the two wells in the 2024 drilling program. On March 21, 2024, TB1 Operator agreed to pick up Falcon’s interest, increasing the Company’s working interest to at least 47.5% over an area of 51,200 acres around the SS2 well pad. This area is capable of holding up to 23 well pads (or 138 wells with 10,000-foot horizontal sections). and the two wells in the 2024 drilling program. We believe the two DSUs will be more than enough to accommodate all wells associated with the Shenandoah South Pilot Project and over 100 wells for future development phases.

In May 2024, Tamboran received approval of its environmental management plan from the Minister for Environment, Climate Change and Water Security to construct up to four exploration and appraisal sites and undertake drilling and flow testing of up to 15 wells in EP 98 and 117 within the Beetaloo Sub-basin for the Beetaloo Joint Venture.

In late August 2024, we commenced our 2024 Beetaloo Basin drilling activities with the spudding of the SS2H well in the Shenandoah South Pilot Project acreage of EP 98 where Tamboran will hold up to 47.5% working interest following the drilling of the initial two wells. The SS2H and Shenandoah South 3H ("SS3H") wells will be drilled from the same well pad with the H&P FlexRig® and will target the Middle Velkerri B Shale at a depth of approximately 9,910 feet (3,020 meters). Both wells are designed to include a 10,000-foot (3,000-meter) horizontal section and will each be stimulated with up to 60 stages utilizing the Liberty Energy's modern frac fleet which has recently been mobilized from the US to Australia. Initial flow test results from each well are expected in 1Q 2025. These SS2H and SS3H will create two DSUs totaling 51,200 gross acres around the new SS2 well pad.

Royalty Owners

We will be required to pay a statutory royalty to the NT Government of 10% of the gross value, at the well-head, of all petroleum produced in connection with a production license or EP in a project area. The gross value of that petroleum is determined by the Petroleum Royalty Act (NT). Additionally, we will pay royalties of between 6% to 11% to other third parties under certain commercial arrangements. See "*—Environmental Matters and Regulation*" and "*—Agreements Relating to the Development of our Assets*" in this report and "*Certain Relationships and Related Person Transactions*" included in the 2024 Proxy Statement for further information.

Mr. Sheffield, our largest shareholder, holds a 2.3% overriding royalty interest ("ORRI") through Daly Waters Royalty over all of our Beetaloo assets.

Sweetpea has granted a 4% ORRI in favor of the Tom Dugan Family Limited Partnership, LLP, Territory Oil & Gas, LLC; Malcolm John Gerrard, and Longview of all petroleum produced from the Sweetpea Assets and the land subject to the Sweetpea Assets.

Sweetpea has 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.

Sweetpea has granted an undivided 1% ORRI in favor 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. The beneficiaries of the Siegel Dynasty Trust are Emily Siegel and Robert Siegel, who are the children of David N. Siegel, who is a director of Longview and a director of the Company. The ORRI extends to all extensions or renewals of each Sweetpea Assets (as applicable) and to any production licenses or subsequent rights to produce petroleum, from those lands, which are granted or issued to Sweetpea, its successors or assignees.

Middle Arm Development

In July 2024, we were granted an Interim Agreement by the NTG over its 420-acre (170-hectare) site at Middle Arm Sustainable Development Precinct (the "Interim MASD Agreement"). The Interim MASD Agreement provides us with future exclusivity over the Wirraway North land until the end of 2027 with two 1-year extension periods and maps out how the Crown Lands department will work with Tamboran for future development of the site. The Interim MASD Agreement is expected to be in place until it is replaced by a commercial lease document just prior to FID. We believe the associated infrastructure at MASD provides us the opportunity to initially export up to 6.6 Mtpa through our proposed NTLNG development. We intend to seek strategic partners in financing and developing the proposed NTLNG development. In June 2023, we announced two non-binding MOUs with bp and Shell to each purchase up to 2.2 Mtpa over a 20-year period from the proposed NTLNG development.

In August 2024, we awarded Bechtel Corporation ("Bechtel") pre-FEED studies for the NTLNG development. Bechtel are the world's leading LNG EPC contractor delivering more than 140 MTPA of LNG (30% of the global LNG production), including nine LNG trains in Australia, with an additional 45 MTPA of capacity currently under EPC, globally. Pre-FEED activities are expected to be completed in 1H 2025 ahead of progression into FEED.

Our Joint Venture Partner

Our largest shareholder is Bryan Sheffield. Mr. Sheffield, through Sheffield Holdings, LP, first began acquiring interests in TR Ltd. in November 2021, has made three subsequent equity investments, and has now grown to become Tamboran's largest shareholder, currently holding beneficial ownership of approximately 15.8% of outstanding common stock. Mr. Sheffield has significant investment experience in the U.S. unconventional energy sector. He previously served as the Chairman, CEO and Founder of Parsley Energy Inc., a major independent unconventional oil and gas producer in the Permian Basin in Texas. Parsley Energy was acquired by Pioneer Natural Resources Company in January 2021 for $7.3 billion. He is currently the Managing Partner of Formentera Partners, an energy private equity firm, which has raised $1.2 billion in equity since 2021.

In September 2022, Mr. Sheffield, through Daly Waters, partnered with TR Ltd. through a newly formed 50 / 50 joint venture, TB1, to acquire a 77.5% interest in EPs 76, 98, and 117 covering approximately four million gross acres (1.5 million net acres).

Agreements Relating to the Development of our Assets

TB1 Joint Venture Agreement

We are a member of TB1, a 50/50 joint venture, through our wholly owned subsidiary, TR West, with Daly Waters, an entity controlled by Bryan Sheffield. TB1 in turn wholly owns TB1 Operator. Capitalized terms used but not defined in this section or elsewhere in this report have the meanings ascribed to them in the applicable agreement.

Under the terms of TB1's amended and restated joint venture and shareholders agreement dated June 3, 2024 (the "TB1 Joint Venture Agreement"), TB1 is governed by a board (the "TB1 Board") of not more than six members, with the number of directors appointed by the joint venture parties in respect of their proportion of equity ownership. The parties have no right to designate directors at such time as such party's ownership falls below 10% of the outstanding equity interests in TB1. The TB1 Board currently consists of four board members; two designated by the Company (Joel Riddle and Patrick Elliott) and two designated by Daly Waters (Stephanie Reed and Blake London).

We are the manager of TB1 with responsibility to carry out day to day operations, including managing the activities of the TB1 Operator in operating the properties and complying with the Beetaloo JOA and Falcon Agreement. The manager is also responsible for submitting work plans and budgets with respect to the development of the properties by the TB1 Operator, in accordance with the terms of the Beetaloo JOA, and submitting production and retention licenses. Under the TB1 Joint Venture Agreement, we have agreed to use all reasonable endeavors to apply for a production license for certain permit areas, where justified by appraisal results, by June 30, 2025.

Special Approvals

Under the TB1 Joint Venture Agreement, TB1 is not permitted to take any of the following actions without the affirmative consent of 75% or more of the total number of votes cast by directors present and entitled to vote at a duly convened meeting of the TB1 Board:

- entering into any partnership or joint venture;
- entering into any new borrowing facility in excess of $5 million;
- decisions to dispose of or vary the terms of a permit or apply for any new permit;
- decisions to proceed to development or production;
- sell or otherwise dispose of assets valued at A$5 million or more;
- entering into any material agreement with any director, shareholder of any affiliate of the foregoing;
- approval of any work program and budget, or any revision of the scope of any approved work program and budget, or approval of variances to any such work program or budget;
- approval under the Beetaloo JOA of any authority for expenditure in excess of $250,000;
- approval to award any contract for Joint Operations over $250,000; and
- all decisions under, or any amendment or variation of, the Gas Sale Agreement between TB1 and Origin Retail dated September 18, 2022 (the "Origin GSA").

In addition, without the prior approval of shareholders holding 75% or more of the total number of votes cast by shareholders present and entitled to vote at a duly convened meeting of the shareholders, TB1 will not take any of the following actions:

- amendment of the constitution;
- loans or financial accommodations with shareholders;
- incurring liability under any guarantee or indemnity;
- issuing new shares or other securities not contemplated by the TB1 Joint Venture Agreement;
- changing the issued share capital;
- cessation of or material alteration of the scale of operations;
- disposal or encumbering of the shares in a subsidiary; and
- seeking an initial public offering on any securities exchange.

Sole Funding Period

Under the TB1 Joint Venture Agreement, we have agreed to fund TB1's 77.5% working interest in the permits for Operations conducted during the sole funding period, including the cost to drill, multi-stage hydraulic fracture stimulate and flow-test the A2H and SS1H wells for at least 60 days. The sole funding period finalized on March 25, 2024, after completing the flow test of the SS1H well for a total of 60-days. Following the sole funding period, each of the joint venture parties is required to fund its respective equity share of working capital costs in proportion with its equity interest in TB1, in accordance with the cash call schedule described in an approved work program and budget.

Cash Call and Dilution

If a party fails to make a required cash call, the other party may elect to make the contribution on such defaulting party's behalf and cause the contributed amount to constitute debt owing from the non-contribution party bearing interest at consistent with the Agreed Interest Rate defined in the Beetaloo JOA, defined generally as average quote rate for 90-day Australian bills of exchange plus 4%. Alternately, a party may make the contribution on such defaulting party's behalf and cause the contributed amount to constitute additional equity, receiving additional shares in TB1 at a value of A$1.00 per share.

Technical Committee

The shareholders shall maintain a committee to supervise and be responsible for providing recommendations to the Board in respect of technical and other matters relating to the exploration, development and operation of the TB1 Operator. If the Technical Committee is split on any recommendations to be made to the Board, members of the Technical Committee representing Daly Waters shall have the right to make the final decision on which such recommendations shall be made to the TB1 Board.

Conversion to Checkerboard

Checkerboard Strategy means an approach to dealing with the Permits whereby Tamboran and Daly Waters pursue a split of 50% of TB1 Operator's interest in the Permits such that the title and ownership of the Permits will be split evenly, as between Tamboran and Daly Waters, in terms of equity interest and operated blocks in respect of the specific area.

At any time, following approval of a Development Plan, either joint venture party may direct the Technical Committee to provide a recommendation to the TB1 Board in relation to the proposed Checkerboard Strategy and the Technical Committee must, acting in good faith, consider the best approach to implementing the Checkerboard Strategy.

Approximately 60 NT Graticular Blocks of roughly 22,115 acres each will be divided into Checkerboard Blocks of 10 NT Graticular Blocks each. These Checkerboard Blocks will be split between us and Daly Waters by a process where Daly Waters will have first choice of Checkerboard Block, and Tamboran and Daly Waters shall thereafter go back and forth in selecting each successive remaining Checkerboard Block.

In their respective checkerboard blocks, Daly Waters and Tamboran will each hold a direct interest in the individual Production Licenses in an equivalent proportion to TB1 Operator's participating interests in the Beetaloo Joint Venture. By way of example, if TB1 Operator holds a 77.5% interest in the Beetaloo Joint Venture at this time, then either Daly Waters or Tamboran shall hold a direct 77.5% interest in the Production License (with Falcon holding the other 22.5%).

The foregoing does not apply to the First Strategic Development Area, an area described as 4 NT Graticular Blocks of roughly 22,115 acres each that includes the SS-1 well pad and its DSU acreage of 20,480 acres, which will remain held by TB1 Operator and subject to the TB1 Joint Venture Agreement and the Beetaloo JOA.

If the Checkerboard Strategy is not implemented by December 31, 2024, due to either (i) ministerial approval to effectuate the Checkerboard Strategy having not been obtained or (ii) a new joint venture not being approved with respect to joint operations in the area pursuant to the Beetaloo JOA, Tamboran must, by February 15, 2025, at its option, either pay Daly Waters a cash amount equal $7.5 million, or issue CDIs to Daly Waters with a value of $15 million based on the weighted average price of the CDIs. These obligations are waived if Tamboran issues to Daly Water, or its nominee, common stock with a value of $7.5 million, where the value of each share of common stock is equal to the price to the public of our common stock issued in an initial public offering raising gross proceeds of at least $75,000,000. If and when approved at our Annual Meeting of stockholders, we intend to issue to Daly Waters, or its nominee, $7.5 million in shares of our common stock in the Daly Waters Placement at the initial public offering price in satisfaction of the waiver requirements for the payment obligations due in 2025. The obligation to implement the Checkerboard Strategy does not cease with the payment.

Conversion of Daly Waters' interest in Tamboran to a direct interest in the Beetaloo Joint Venture

At any time during the period beginning on the date that the sole funding period ended (March 25, 2024) until December 31, 2026, if the Checkerboard Strategy remains uncompleted Daly Waters may elect to have us buy-back or otherwise convert its 50% interest in TB1 into a 38.75% direct participating interest in the Beetaloo Joint Venture.

Following the end of any fiscal year, provided profits are available for distribution, TB1 must pay a dividend in respect of each of TB1's members' respective equity interest. TB1 will distribute all profits, provided that profits may be retained to meet any capital adequacy or solvency requirements and is able to pay its debts as and when they fall due, or as required by applicable law or specified in an approved work plan.

Each of the members of TB1 have certain pre-emptive rights. Each joint venture party has a right of first offer and right to match any third party offers in connection with any proposed transfer of equity interests in TB1. The TB1 Joint Venture Agreement also permits a party to "drag" the other in a sale of the joint venture if that selling party holds at least 75% of the equity interests in TB1. Each party likewise has the right to participate or tag along in any sale by the other party of 75% or more of the equity interests.

Upon the occurrence of any default under the TB1 Joint Venture Agreement (which includes the failure to pay amounts due), the other party may elect to purchase all of the defaulting party's equity in TB1 at a price equal to 95% of fair market value.

Falcon Agreements

The TB1 Operator is a party to a farmin agreement with Falcon (the "Falcon Agreement") pursuant to which the TB1 Operator owns a 77.5% operated working interest and Falcon owns a 22.5% non-operated working interest in EPs 76, 98, and 117. Under the terms of the Falcon Agreement, the TB1 Operator will undertake operations on the properties and bear the costs of the work program up to an overall spending cap of A$263.8 million, following which the parties shall contribute in respect of their proportionate interests in TB1. In August 2023, the spending cap was reached.

The TB1 Operator is also a party to a joint operating agreement with Falcon (the "Beetaloo JOA"). The Beetaloo JOA establishes the respective rights and obligations of the TB1 Operator and Falcon in connection with EP 76, 98, and 117. The TB1 Operator is designated as the operator under the Beetaloo JOA. Pursuant to the Beetaloo JOA, Falcon capped its participation to 5% in the Shenandoah South Pilot Project and TB1 has agreed to pick up Falcon's interest, increasing the Company's working interest to at least 47.5% in the Beetaloo Joint Venture's SS2 and the two wells in the 2024 drilling program. TB1 Operator will carry Falcon for up to A$3.75 million gross (A$1.875 million net) for SS2 after June 30, 2024.

On March 21, 2024, TB1 Operator agreed to acquire Falcon's interest, increasing the Company's working interest to at least 47.5% in SS2 and the two wells in the 2024 drilling program. TB1 Operator will carry Falcon for up to A$3.75 million gross (A$1.875 million net) for SS2 after June 30, 2024.

McArthur Joint Operating Agreement

On December 11, 2012, we entered into a joint operating agreement (the "McArthur JOA") with Santos QNT under which Santos serves as the operator of EP 161. The McArthur JOA will remain in effect as long as the permits remain in force in the names of two or more parties. Our current working interest under the McArthur JOA is 25%. We must continue to contribute our proportionate share of expenditures to maintain our interest in the underlying permits. Before incurring any commitment or expenditure greater than A$2,000,000, Santos must receive approval from an operating committee consisting of a representative from each of Tamboran and Santos. We have committed approximately $2.7 million through March 2026 based on minimum work requirements.

We hold a non-operated 25% working interest in EP 161 through our wholly owned subsidiary Tamboran (McArthur) Pty Ltd, with Santos holding the remaining 75% working interest as operator. Pursuant to our joint operating agreement with Santos QNT, we are required to contribute our proportionate share of expenditures in order to maintain our interest in EP 161.

Drilling Contract with H&P

On September 9, 2022, we, through a wholly owned subsidiary, entered into a drilling contract with H&P (as amended, the "Drilling Contract"). The term of the Drilling Contract commenced on July 1, 2023. Under the Drilling Contract, and associated agreements, we granted H&P a 10-year preferential right to provide drilling services to us in connection with our exploration and production activities in Australia. We paid H&P a mobilization fee of $15,000 per day plus all associated costs for shipping from Houston, Texas to the first location being the SS1H well pad. The total import cost for Rig 469 was $7.5 million. We will also pay an operating rate of $39,500 per day. The contract also provides for us to pay H&P a demobilization fee equal to the documented trucking and mobilization costs to a mutually-agreed location in Australia. Under the Drilling Contract we have an option to contract for up to four additional rigs. On July 31, 2023, we, through a wholly owned subsidiary, entered into a Rig Sharing and Temporary Assignment and Assumption Agreement with the wholly owned subsidiary of TB1 to utilize the Drilling Contract for the purposes of drilling the Beetaloo Joint Venture's appraisal wells.

Strategic Arrangement with Liberty Energy Inc.

We have entered into a two-year preferred arrangement with Liberty Energy to provide us dedicated frac fleets and personnel on market terms (as reasonably determined by the Beetaloo Joint Venture), which includes Liberty Energy's latest sand mining and handling management solution. We believe that a strategic arrangement with Liberty Energy will enable us to reduce delays typically experienced in transporting equipment to worksites, while increasing completion efficiencies and reducing costs. Liberty Energy is also partnering with us through its purchase, on December 14, 2023, of our CDIs for an aggregate consideration equal to $10.2 million (A$15.3 million). We do not have any obligations to purchase services from Liberty Energy under this arrangement. In August 2024, the stimulation equipment arrived in Darwin ahead of being mobilized to the Beetaloo Basin. The equipment is planned to be used to conduct up to 60 stimulation stages each within the 10,000-foot lateral sections of the SS2H and SS3H wells during the second quarter of fiscal year 2025.

APA Agreements

We entered into three framework agreements on December 15, 2023 with APA Group (collectively, the "APA Agreements") to support the development of our Beetaloo assets and enable distribution of natural gas from our assets:

- Under the APA Partnering Agreement, we agreed to work exclusively with APA Group on pipeline projects in the Beetaloo, and subject to conditions being met, we may obtain an option to acquire up to 15% of any Beetaloo pipeline project in the lead up to a final investment decision.
- The Early Development Agreement Sturt Plateau Pipeline Project (the "SPP EDA") progressed discussions relating to the construction of the Sturt Pipeline Project, a natural gas pipeline capable of transporting up to approximately 95 MMcf/d (the "SPP Pipeline Project") from a proposed raw gas processing plant located near Shenandoah South to the AGP and the potential provision of gas transportation services on the AGP to enable connection of the Shenandoah South to the AGP. The SPP EDA contemplates completion of the SPP Pipeline Project by March of 2026. The delivery of the SPP Pipeline Project will be the subject of a future development agreement and the gas transport services will be the subject of a future gas transportation agreement. APA Group has commenced the Early Works defined in the SPP EDA, which include efforts to design and engineer the SPP Pipeline Project, obtain access and approvals, along with developing revised project schedules and estimates.

- The Early Development Agreement Beetaloo to East Coast Pipeline (the "BEC EDA") progressed discussions relating to the construction of a large natural gas pipeline (the "BEC Pipeline Project") to connect a central point in our Beetaloo acreage to the Australian east coast network of gas pipelines owned or operated by the APA Group ("East Coast Grid") and the provision of gas transportation services on the BEC Pipeline Project to enable connection of the Beetaloo to the East Coast Grid. The delivery of the BEC Pipeline Project will be the subject of a future development agreement and the gas transport services will be the subject of a future gas transportation agreement. APA Group has commenced the Early Works defined in the BEC EDA, which include certain efforts to obtain access and approvals, along with developing revised project schedules and estimates.

Under the SPP EDA and BEC EDA, APA has agreed to continue evaluation of the proposed pipelines with early works expenditure of up to A$10 million on the basis that we continue to progress and achieve certain agreed milestones conditions, such as the availability of sufficient financial resources to drill additional wells and us taking material steps toward the drilling of additional wells. The APA Agreements are preliminary agreements related to the development of the projects, and as such, neither we nor APA Group will have material binding obligations until definitive agreements are signed.

Origin Retail Gas Sales Agreement

On September 18, 2022, the TB1 Operator entered into the Origin GSA whereby the TB1 Operator has agreed to supply, and Origin Retail has agreed to purchase up to 5.97 Mmboe per annum (2.99 Mmboe per annum net to Tamboran), gas sourced from EP 98, 76, or 117. The start date of the supply period under the Origin GSA must be between January 1, 2025 and December 31, 2028, and the end date is 10 years following the start date unless extended. Origin Retail is not obligated to perform under the Origin GSA until the TB1 Operator has satisfied certain conditions precedent, including making positive final investment decisions to proceed with the development of gas permits of a certain quantity sufficient to produce a minimum of ~30 MMcf/d; and to proceed with constructing a pipeline from those permits to any location with physical capacity to transport that volume; and all required regulatory approvals are received. We are not obligated to perform under the Origin GSA unless a quantity of ~50 MMcf/d or greater is produced.

NT Government Gas Sales Agreement

On April 23, 2024, the Beetaloo Joint Venture signed a long-term gas sales agreement (the "NT GSA") to supply the NT Government with ~40 MMcf/d (~19 MMcf/d net to Tamboran) from the proposed Shenandoah South Pilot Project for an initial term of nine years, starting in H1 2026. The Buyer has an option to extend the NT GSA for a further 6.5 years through to 2042.

The NT GSA includes a number of conditions precedent that require satisfaction in order for the agreement to become binding. Specifically, the NT GSA is conditional on the Beetaloo Joint Venture entering into a binding gas transportation agreement with APA on the proposed Sturt Plateau Pipeline, a binding gas processing agreement for the SPCF, reaching a final investment decision on the Shenandoah South Pilot Project which we anticipate occurring in mid-2024, and receiving key regulatory and stakeholder approvals. Once the NT GSA becomes binding, the Beetaloo Joint Venture is required to have the daily quantity of gas available each day. Should this not occur, and there is a shortfall, the Beetaloo Joint Venture may be liable to pay shortfall liquidated damages.

Customers and Marketing

We plan to market our natural gas under long-term agreements. Our ability to market natural gas will depend on many factors beyond our control, including the extent of domestic production and imports of oil and natural gas, available storage, the proximity of our natural gas production to pipelines and corresponding markets, the available capacity in such pipelines, the demand for natural gas and oil, the effects of weather, and the effects of state and federal regulation. There is no assurance that we will always be able to market all of our production or obtain favorable prices.

Seasonality

Weather conditions have a significant impact on the demand for natural gas used for heating loads and natural gas-fired power generation. Demand for natural gas is generally at its lowest during the spring and fall months and peaks during the summer and winter months. Demand in the winter season peaks due to residential and commercial heating load demand, while the summer season peaks due to cooling loads, which calls on increased natural gas fired power generation loads. However, seasonal anomalies such as warmer than normal winters or cooler than normal summers can lessen the magnitude of the seasonal fluctuations in demand. In addition, natural gas storage facilities are utilized to bring additional supply to the market that is utilized to meet peak demand levels during both winter and summer seasons. The Northern Territory also typically experiences greater rainfall from November to April. Although this season does present challenging conditions for operations, operators have drilled, stimulated and tested through the wet season successfully.

Competition

The oil and natural gas industry is intensely competitive, and we compete globally with other companies that have greater resources. Many of these companies not only explore for and produce natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in evaluating and bidding for oil and natural gas properties.

There is also competition between natural gas producers and other industries producing energy and fuel, including coal, other petroleum products and renewables. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of Australia. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of developing natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Human Capital Resources

As of June 30, 2024, we employed 39 people full time and did not have any part-time employees. We hire independent contractors on an as needed basis. We believe we have good relations with our employees. We and our employees are not members of any labor union. We prioritize local hiring for both employees and contractors, particularly in areas of field operations, to support employment opportunities in our local communities.

Safety and training

Safety is our highest priority, including the prevention of any releases from our operations. We conduct routine maintenance and inspections at our facilities, and we have established practices and operational infrastructure to control and mitigate potential spills or discharges. We also provide training to our staff and contractors that cover spill response and reporting and ensure our teams are fully trained on our response plan in the event of any releases. We believe these measures continue to strengthen our process safety culture. We have a full-time Senior Manager of Health, Safety and Environmental who is responsible for training, evaluation and risk mitigation as well as implementing safety measures.

Compensation and Benefits

We recognize that our employees are our most valuable resource and that we must provide competitive compensation to ensure we attract and retain top talent. We believe we offer competitive and comprehensive compensation and benefits packages that includes access to financial, health and wellness programs, a matched 401(k) plan, short-term and long-term incentive plans, medical, dental, and vision insurance coverage, and paid time off for holidays, sick leave, and vacation. We continue to survey and update our pay structure to stay competitive with our peers. Our compensation packages are reviewed annually by NFPCC Compensation Consulting, a leading independent global compensation consultant.

Sustainability and ESG

Sustainability is a central component of our ESG corporate strategy, including continued focus on the Company's impact on the environment, and relationships with Traditional Owners, key stakeholders and employees. As an energy company with assets in the pre-development stage, we have the opportunity to integrate environment, community and social matters into the center of what the Company delivers. By focusing on the sustainable development of our Beetaloo natural gas project, we aim to grow local jobs, strengthen communities and deliver a positive social impact. We are committed to respecting the unique environment in the Northern Territory and working closely with the local communities to understand their diverse views on development and the impact on the environmental. To highlight the importance of Sustainability and ESG, the Company has a Six-Pillar Sustainability Plan, which includes: (i) Community: Partnering with local and host communities to share value through the creation of local jobs and business opportunities; (ii) Climate Change: Playing an effective role in the transition to a lower carbon economy through the production of low CO2 natural gas resources (primarily through committing to operational net zero and integrating renewable energy and carbon offsets into developments); (iii) Environment: Applying technologies to minimize environmental impacts; (iv) Health and Safety: Prioritizing the health and safety of people; (v) People: Aiming to attract, develop and retain a diverse, inclusive, and competent workforce; and (vi) Economic Sustainability: Generating economic growth and value for investors, employees, customers and communities. The Safeguard Mechanism (legislation.gov.au) provides regulations that shale gas facilities will have a "zero baseline" meaning they must have Net Zero Scope 1 emissions by law.

Environmental Matters and Regulation

We are, and our future operations will be, subject to various stringent and complex international, foreign, federal, state and local environmental, health and safety laws and regulations governing matters including the emission and discharge of pollutants into the ground, air or water; the generation, storage, handling, use and transportation of regulated materials; and the health and safety of our employees. These laws and regulations may, among other things:

- require the acquisition of various approvals and permits before drilling or other regulated activities commence;
- enjoin some or all of the operations of facilities deemed not in compliance with permits or approvals;
- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with natural gas drilling, production and transportation activities;

- limit or prohibit drilling activities in certain locations lying within protected or otherwise sensitive areas; and
- require remedial measures to mitigate pollution from our operations.

These laws and regulations may also restrict the rate of natural gas production below the rate that would otherwise be possible. Compliance with these laws can be costly; the regulatory burden on the natural gas industry increases the cost of doing business in the industry and consequently affects profitability.

Moreover, public interest in climate change and the protection of the environment has increased in recent years. Drilling in some areas has been opposed by activists, including environmental groups, and, in some cases, been restricted. Our operations could be adversely affected to the extent laws are enacted or other governmental action is taken that prohibits or restricts offshore drilling or imposes environmental requirements that result in increased costs to the natural gas industry in general, such as more stringent or costly waste handling, disposal or cleanup requirements.

Regulatory framework

The following is a summary of the more significant existing onshore gas laws, as amended from time to time, to which our business operations are or may be subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Many of these laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating exploration, certain drilling, construction, production, operation, or other natural gas activities, and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal, or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines, and other operations.

Regulation of our exploration activities

The *Petroleum Act* requires Tamboran to hold EPs in all areas where its exploration activities are proposed. The Petroleum Act is the principal legislation dealing with petroleum exploration and production activities onshore and in the territorial waters of the Northern Territory ("NT"). In particular, the Petroleum Act provides the legal framework for: (i) the grant of permits for exploration, production, and ancillary activities associated with exploiting petroleum, (ii) the renewal or transfer of those permits, (iii) the promotion of active exploration for petroleum, and (iv) the appraisal of discoveries and of the development of petroleum production if commercially viable by persons granted production licenses. Further, the Petroleum Act provides for the assessment of proposed technical works programs for the exploration, appraisal, recovery or production of petroleum, including an assessment of the financial capacity of persons proposing to carry out those programs. The Petroleum Act provides for Ministerial directions regarding resource management, approval of activity and infrastructure plans before production, audit activities by regulators, and includes a financial assurance framework that encompasses environmental securities, monitoring and compliance levies and an orphan well levy.

The objectives of the *Petroleum Regulations 2020 (NT)* ("Petroleum Regulations") are to provide for land access agreements between interest holders and the owners or occupiers of land covered by petroleum interests, to support and enhance the integrity of onshore petroleum wells, petroleum surface infrastructure by ensuring that risks are reduced to as low as reasonably practicable, and the strategic management of petroleum production. In accordance with the Petroleum Regulations, Tamboran is required to enter into land access agreements with the owners or occupiers of the land on which it conducts its activities before it conducts regulated operations. The Petroleum Regulations govern the minimum conditions of entry into these access arrangements with the owners or occupiers. The Petroleum Regulations also prescribe the fees Tamboran must pay relating to the general administration of its petroleum titles, including fees for the grant, renewal and variation of EPs, retention licenses and production licenses.

The object of the *Petroleum (Environment) Regulations 2016 (NT)* ("Petroleum Environment Regulations") is to ensure that regulated activities are carried out in a manner that is consistent with the principles of ecologically sustainable development, and by which the environmental impacts and risks of the activities will be reduced to a level that is as low as reasonably practicable and acceptable. The Petroleum Environment Regulations require the preparation of environment management plans for regulated activities and mandates such plans be approved by the Minister. Tamboran, as the permit holder, has environment management plans ("EMP") in place in respect of all its regulated activities. These activities include conducting seismic surveys, the construction, operation, modification, decommissioning, dismantling or removal of a wells or other facilities, drilling, hydraulic fracturing, the release of contaminants or waste, and the storage and transportation of petroleum and hazardous waste. Tamboran's EMPs are publicly available on the NT Government Department of Environment, Parks and Water Security website *www.depws.nt.gov.au/EMPs*. The EMPs describe how our regulated activities might impact the environment in which the activity occurs and establishes Tamboran's obligations to ensure those impacts are managed to an environmentally acceptable level. Civil and criminal penalties apply under the Petroleum Environment Regulations for conduct which results in a contravention of an EMP, as well as for undertaking regulated activity for which there is no approved EMP.

The Petroleum Environment Regulations contain record-keeping and reporting requirements. Specifically in relation to our hydraulic fracturing activities, Tamboran is required to provide the Minister with a report about flowback fluid within six months of the flowback occurring. This report must contain a full human health risk assessment relating to any chemical found in the flowback fluid or water produced. Reporting is also required for incidents arising from regulated activities that have or have the potential to cause material environmental harm. Failure to comply with these reporting requirements may result in significant financial penalties.

The *Code of Practice: Onshore Petroleum Activities in the NT* (the "Code of Practice") provides minimum standards that the onshore petroleum industry in the Northern Territory must adhere to. The Code of Practice applies to all of Tamboran's regulated activities including those associated with both unconventional gas and exploration, appraisal and production activities. Tamboran's Well Drilling, Hydraulic Fracture Stimulation and Well Testing EMPs must demonstrate compliance with the Code of Practice and will not be approved or renewed if they are not compliant with the requirements of the Code of Practice.

The *Petroleum Royalty Act 2023* (NT) ("Royalty Act") imposes a royalty rate, paid to the NT Government, for petroleum produced from a project area of 10% of the gross value of the petroleum at the well head (including petroleum produced from a production project area that is used or lost through venting or flaring or other means, but excluding petroleum used by the licensee for incidental purposes, petroleum used in the project area for processing or compression, or preparing petroleum for sale, petroleum returned or reinjected into a natural reservoir in the project area from which it was extracted/recovered, and petroleum produced from an exploration project area that is used or lost through venting or flaring or other means). "Petroleum" means a naturally occurring hydrocarbon, whether in gaseous, liquid or solid state.

As onshore gas extraction moves toward production in the Northern Territory, there could be an increased risk of litigation in the form of challenges to Ministerial approvals of EMP, which could lead to costs and delays with respect to regulated activities. The failure to comply with record-keeping and reporting requirements of the Petroleum Environment Regulations can also attract financial penalties. Tamboran's competitors in the Northern Territory are subject to the same risks and requirements that affect Tamboran's operations.

Regulation of GHG Emissions

The *National Greenhouse and Energy Reporting Act 2007* (Cth) ("NGER Act") establishes the legislative framework for reporting greenhouse gas emissions, greenhouse gas projects and energy consumption and production by corporations in Australia. The objects of the NGER Act are to introduce a single national reporting framework for the reporting and dissemination of information related to greenhouse gas emissions, greenhouse gas projects, energy consumption and energy production of corporations and to contribute to the achievement of

Australia's greenhouse gas emissions reduction targets. Under the NGER Act, Tamboran will report Scope 1 GHG emissions from its operations to the Australian Government's Clean Energy Regulator (CER). Furthermore, the Safeguard Mechanism, a legislative instrument sitting under the NGER Act, is designed to reduce emissions from large industrial facilities. It sets legislated limits, known as baselines, on the greenhouse gas emissions of certain facilities. The Safeguard Mechanism applies to industrial facilities emitting more than 100,000 tons of CO2-e per year and requires that all emissions form the Beetaloo be offset with Australian Carbon Credit Units or Safeguard Mechanism Credits once the 100,000 tons CO2-e trigger is exceeded.

The Safeguard Mechanism requires that all Beetaloo facilities covered by the Safeguard Mechanism have Net Zero Scope 1 emissions. Accordingly, the Safeguard Mechanism will apply to Tamboran. Tamboran's ability to achieve Net Zero Scope 1 emissions will depend on it being able to economically manage its carbon emissions, which could, for example, be impacted by availability of future revenues to fund various carbon initiatives, market pricing of carbon offsets, technological developments affecting operations and costs of implementing sustainable practices. Under the Safeguard Mechanism, upon exceeding the 100,000 tons CO2-e trigger in a given financial year, all Scope 1 emissions in that financial year are required to be offset. The Australian Federal Government has established an A$75 carbon offset price cap for FY24. The offset price cap increases by CPI plus 2% each year. While we are unable to predict the future costs or impact of compliance with the Safeguard Mechanism, we do have established procedures for the ongoing evaluation of our operations to identify costs, potential exposures and to track compliance with this legislation.

On April 17, 2018, the NT Government announced that it accepted all 135 of the recommendations set out in The Scientific Inquiry into Hydraulic Fracturing in the Northern Territory. The implementation of the recommendations has resulted in a more rigorous regulatory regime by placing additional obligations on oil and gas companies including the introduction of a stricter code of practice for decommissioning onshore shale gas wells, requiring tenement holders to provide a non-refundable levy prior to granting any further production approvals and introducing no go zones where a person cannot explore or drill for petroleum resources.

Although it is not possible at this time to predict how new laws or regulations in Australia that may be adopted or issued to address GHG emissions would impact our business, any such future laws, regulations or legal requirements imposing reporting or permitting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to comply with new requirements and to reduce emissions of GHGs associated with our operations as well as delays or restrictions in our ability to permit GHG emissions from new or modified sources. In addition, substantial limitations on GHG emissions could adversely affect demand for natural gas we aim to produce.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent Australian Federal Government and territory laws and regulations governing occupational safety and health aspects of our operations, the discharge of materials into the environment and the protection of the environment and natural resources (including threatened and endangered species and their habitat and certain other protected sites). Numerous governmental departments have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions.

These laws and regulations may, among other things (i) require the acquisition of permits to conduct drilling and other regulated activities; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and on-going operations, such as specific waste removal requirements; (v) apply specific health and safety criteria addressing worker protection; and (vi) impose substantial liabilities for pollution resulting from drilling and other regulated activities. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the occurrence of delays or restrictions in permitting or performance of projects, and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of natural gas production below the rate that would otherwise be possible. The regulatory burden on the natural gas industry increases the cost of doing business in the industry and consequently affects profitability. The trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment, and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly well drilling, construction, completion or water management activities, or waste handling, storage transport, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our customers once we commence production. Moreover, accidental releases or leaks may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. The cost of continued compliance with existing requirements is not expected to materially affect us. However, there is no assurance that compliance costs will remain the same in the future for such existing or any new laws and regulations or that costs related to such future compliance will not have a material adverse effect on our business and operating results.

The following is a summary of the more significant existing and proposed environmental and occupational safety and health laws, as amended from time to time, to which our business operations are or may be subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Any of our activities which have the potential to cause a significant impact to the environment are required to be referred to the NT Environmental Protection Authority ("EPA") for assessment under the *Environmental Protection Act 2019 (NT)* ("Environment Protection Act"). Tamboran has completed a self-assessment for its current environmental impact and considers its potential environmental impact to not be significant. However, it is anticipated that future developments by Tamboran could trigger a referral to, and assessment by, the EPA, and require Tamboran to obtain approvals under the Environmental Protection Act to conduct the activity (an "Environmental Approval"). Civil proceedings could be brought by any person who is affected by an alleged act or omission that contravenes the Environment Protection Act. Contraventions of an Environmental Approval can attract penalties currently ranging from $67,760 to $3,386,240. Contravention can also result in revocation of the Environmental Approval.

The *Environment Protection Legislation Amendment Bill 2023* (NT) ("EPLAB"), assented to on December 6, 2023, amends the *Environment Protection Legislation Amendment (Chain of Responsibility) Act 2022* (NT) ("CoR Act") to extend chain of responsibility provisions of the CoR Act. Although the CoR Act has been assented to, its provisions have not yet commenced, but are expected to do so on July 1, 2024. The CoR Act, once commenced, amends the Environment Protection Act to introduce environmental chain of responsibility provisions. Environmental chain of responsibility laws are a regulatory approach that has been developed to protect the Australian government and taxpayers from inheriting financial liabilities that arise when Environmental Approval holders for petroleum activities contravene statutory compliance obligations, such as the costs associated with cleaning up environmental damage, by redirecting liability to a related person with a relevant connection who may not have otherwise been liable (depending on the circumstances, such as directors, shareholders and associated entities). Under the CoR Act, a petroleum activity is an activity for which an EP, retention license or production license is required. Once the provisions of the CoR Act (as amended by the EPLAB) commence, Department of Environment Parks, Water Security could issue a compliance notice to any related person with a relevant connection to an entity conducting a petroleum activity. For corporations, contraventions of a relevant notice can attract a fine of between A$67,760 and A$3,386,240 (based on current penalty unit amounts) depending on the intentions and recklessness in contravening the notice and the severity of harm to the environment caused by failure to comply.

The *Environment Protection and Biodiversity Conservation Act 1999* (Cth) ("EPBC Act") is Australia's primary federal environmental legislation, which provides for the protection and conservation of matters of national environment significance ("MNES") and heritage. This includes the protection and management of national and internationally important plants, animals, habitats and places. The objects of the EPBC Act are to promote ecologically sustainable development through the conservation and ecologically sustainable use of natural resources, the conservation of biodiversity and co-operative approach to the protection and management of the environment involving governments, the community, landholders, and Indigenous peoples. Any person who proposes to take an action which involves a coal seam gas development or a large coal mining development that will have, or is likely to have, a significant impact on a water resource is required to submit a referral to the Australian Government Department of the Environment for a decision by the Minister on whether assessment and approval is required for that action under the EPBC Act. We have completed self-assessments as part of certain EMP applications to determine whether a MNES is likely to be impacted by the proposed activities and concluded that significant impacts to water resources and other MNES are not anticipated to occur. However, it is anticipated that any future development could require referral and assessment under the EPBC Act.

The *Water Act 1992 (NT)* ("Water Act") controls and licenses the taking of groundwater for petroleum operations and the disposal of hydraulic fracturing waste. Specifically, the Water Act provides for the investigation, allocation, use, control, protection, management and administration of water resources in the Northern Territory and imposes restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of hazardous substances. The Water Act requires Tamboran to obtain permits to extract groundwater for petroleum operations and controls the contact of hydraulic fracturing waste with water that is not contained in the geologic formation target by the process of hydraulic fracturing. It also prohibits taking surface water and releasing wastewater into surface water. Tamboran has obtained a Water Extraction License "WEL GRF 10285 (175 ML/year)" (WEL) and Sweetpea Petroleum also has a Water Extraction License "WEL GRF 10346 (299 ML/year)" covering previous water usage for exploration activities over specific parcels of land in the Northern Territory. WELs are renewed periodically to support operational activities. The WEL will be increased to cover the future proposed exploration activities.

The *Waste Management and Pollution Control Act 1998* (NT) ("Waste Management Act") governs the management of waste and pollution prevention and control practices for related purposes. Tamboran is required to store, transport and dispose of waste in compliance with the requirements of the Waste Management Act. For instance, the transportation and disposal of waste may only be completed by a licensed contractor and at a licensed disposal facility. Any interstate disposal should be completed with an approved consignment authority. The Waste Management Act does not apply in relation to a contaminant or waste that results from, directly or indirectly, the carrying out of a petroleum exploration activity or petroleum extraction activity by a person on land on which the activity is authorized under the Petroleum Act, and where that contaminant or waste is confined within the land on which the activity is being carried out. Where any contaminant or waste is not confined within the land on which the activity is being carried out, the Waste Management Act imposes certain duties on Tamboran to take all measures that are reasonable and practicable to prevent or minimize pollution or environmental harm and reduce the amount of the waste, if it conducts an activity or performs an action that causes or is likely to cause pollution resulting in environmental harm or that generates or is likely to generate waste. We currently own, lease, or operate numerous properties that have been used for natural gas exploration for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, waste, or petroleum hydrocarbons may have been released on, under, or from, the properties owned or leased by us, or on, under, or from, other locations, including offsite locations, where such substances have been taken for treatment or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, waste, or petroleum hydrocarbons were not under our control. These properties and the substances disposed or released on, under or from them may be subject to the Environmental Protection Act and analogous laws. Under such laws, we could be required to undertake corrective measures, which could include removal of previously disposed substances and waste, cleanup of contaminated property, or performance of remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

The *Work Health and Safety (National Uniform Legislation) Act* (NT) 2011 seeks to secure the health and safety of workers and workplaces imposing general duty of care obligations, seeking the elimination or minimization of risks arising from work or from specified types of substances or plant, providing for workplace representation and consultation in relation to work health and safety, encouraging organizations to take a constructive role in work health and safety practices, promoting the provision of advice and training and providing for compliance and enforcement measures. Tamboran has a Safety Management Plan that outlines how it achieves the requirements of the WHS in relation to its activities. This includes the management of chemical storage dossiers, safety data sheets and appropriate procedures and controls to prevent worker exposure to hazards.

The *Bushfires Management Act 2016*, amongst other things, establishes bushfire fuel management programs and prohibits certain activities during high fire risk periods to prevent the outbreak and spread of bush fires. During total fire ban periods, Tamboran is prohibited from undertaking flaring and is required to obtain a permit for flaring to take place during declared fire danger periods. This could lead to costs and delays with respect to Tamboran's regulated activities. In accordance with the Code of Practice: *Onshore Petroleum Activities in the NT*, Tamboran is required to maintain a Bushfires Management Plan which includes bushfire preventative and response measures.

The *Northern Territory Aboriginal Sacred Sites Act 1989* (NT) ("Sacred Sites Act") establishes a procedure for the protection and registration of Aboriginal sacred sites, provides for entry onto sacred sites and the conditions to which such entry is subject, and establishes a procedure for the avoidance of sacred sites in the development and use of land. The Sacred Sites Act establishes the Aboriginal Areas Protection Authority ("AAPA") for the purposes of administering the Sacred Sites Act and a procedure for the review of decisions of the AAPA by the Minister. Tamboran conducts detailed sacred sites assessments with traditional owners prior to conducting any activities and applies to the APPA for Authority Certificates. These assessments are typically designed to identify sacred places, such as dreaming tracks, song lines, and women's business places, which must be protected. The location of sacred sites are indicated on maps and Tamboran may not conduct activities that could disturb sacred sites without first obtaining clearance and authorization from the traditional owners. An Authority Certificate can be issued by the APPA under the Sacred Sites Act where it is satisfied that in relation to an application, the work or use of the land could proceed or be made without there being a substantive risk of damage to or interference with a sacred site on or in the vicinity of the land, or an agreement has been reached between the custodians and the applicant. Subject to the conditions (if any) of the Authority Certificate, the holder of the Authority Certificate may enter and remain on that or those parts of the land and carry out the work proposed in the application. Due to long distance direction drilling giving flexibility as to drilling pad locations, we consider that the presence of sacred sites should not interfere with future production.

The *Heritage Act 2011* (NT) ("Heritage Act") provides for the conservation of the Northern Territory's cultural and natural heritage. Specifically, the Heritage Act provides for the protection of Aboriginal, European and Macassan archaeological places and archaeological objects. Any interference with an archaeological place or object is strictly regulated under the Heritage Act.

The *Native Title Act 1993 (Cth)* ("Native Title Act") recognizes and protects native title by providing that native title cannot be extinguished contrary to the Native Title Act. The objects of the Native Title Act are to provide for the recognition and protection of native title, establish ways in which future dealings affecting native title may proceed and to set standards for those dealings and mechanisms for determining claims to native title and to provide for, or permit, the validation of past acts, and intermediate period acts, invalidated because of the existence of native title. The Right to Negotiate with Native Title Owners are the most relevant provisions of the Native Title Act to Tamboran's operations. The Right to Negotiate process was applied to the grant of Tamboran's explorations permits, resulting in Section 31 Agreements which provide for the consent of traditional owners for its activities. The traditional owners are and continue to be represented by the Native Land Council ("NLC") in respect of the Agreements. Tamboran continues to implement EPs in collaboration with the NLC, with all work programs being reviewed and approved by traditional owners.

Aboriginal Land Rights (Northern Territory) Act 1976 (Cth) ("ALRA") applies to the Northern Territory and provides for the grant of certain land as Aboriginal land and the protection of sacred sites. Under ALRA the exploration for, and production of, petroleum on Aboriginal land is subject to a regime of consent being required by traditional Aboriginal owners of the land and subject to agreements being entered into with the relevant land council representing the traditional Aboriginal owners.

Compliance with the above regulations and their requirements has the potential to delay the development of natural gas projects and increase our costs of development and production, which costs could be significant. In addition, our failure to comply with any of the regulatory obligations could subject us to monetary penalties, injunctions, conditions or restrictions on operations and criminal enforcement actions.

Other Facilities

Our corporate headquarters are located at Suite 01, Level 39, Tower One, International Towers Sydney, 100 Barangaroo Avenue, Barangaroo NSW 2000, and our telephone number at such address is +61 (2) 8330-6626. Our corporate headquarters and field office facilities are leased, and we believe that they are adequate for our current needs.

Operating Hazards and Insurance

Natural gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of oil, natural gas or well fluids, fires, pipe, casing or cement failures, abnormal pressure, pipeline leaks, ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters and other environmental hazards and risks.

In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We cannot provide assurance that any insurance we obtain will be adequate to cover our losses or liabilities. We have elected to self-insure for certain items for which we have determined that the cost of available insurance is excessive relative to the risks presented. In addition, certain pollution and environmental risks are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position, results of operations and future cash flows.

Title to Properties

Under the Petroleum Act, all petroleum on or below the surface of land within the Northern Territory is and shall be deemed always to have been the property of the Crown (as described in the Petroleum Act). The property in petroleum produced from a well on an area to which a petroleum interest relates passes to the interest holder at the wellhead (and a royalty is payable by the interest holder to the Crown). Petroleum interests under the Petroleum Act primarily take the following forms: Exploration Permits, Retention Licenses and Production Licenses.

Exploration Permits

Rights to conduct natural gas exploration within the Northern Territory are based on EPs. An EP grants the holder the exclusive right to explore for petroleum and to carry on such operations and execute such works as are necessary for that purpose, in the exploration permit area. This includes the rights to carry out the technical works program and other exploration for petroleum in the exploration permit area. Activities under an EP are subject to any conditions imposed on the permit by the Minister.

During the exploration permit application ("EP(A)") phase, the permit holder consults with government authorities and the appropriate native title holders for the area (if there is native title land) and/or traditional owners (where the land is Aboriginal Land) in a negotiation process that determines the terms upon which the native title holders will consent to the grant of the license, including the amount of financial compensation that the permit holder will provide to the native title holders/traditional owners during the exploration period. The negotiations over Aboriginal Land are facilitated by the government regulatory body, in this case the Northern Land Council, who is responsible for assisting Aboriginal People in the Northern Territory to manage their traditional lands. After agreement is reached, which often takes between 3-5 years, the permit holder provides a work program and may receive an EP under which the permit holder has three five-year periods in which to meet or amend its obligations proposed under the EP.

The Petroleum Act requires an EP holder to notify the Minister as soon as possible of a discovery of petroleum within a permit area and within three days provide the particulars of the discovery. Upon discovery of a commercially exploitable petroleum discovery, the permit holder will enter into further discussions with local native title holders (if native title land) (including traditional owners) to enter to into an agreement which satisfies the requirements of the Native Title Act that, among other things, determines the royalty payments to the local traditional owners. Where the Minister is satisfied that the petroleum resources are potentially of a commercial quality and quantity, a permit holder is entitled to apply for either: (a) a production license, in relation to the whole or part of its EP if the discovery is an accumulation of petroleum that is commercially able to be immediately exploited; or (b) one or more retention licenses.

Production Licenses

An EP holder is entitled to apply for a production license if a commercially exploitable petroleum discovery is made. An application for a production license is required to include certain information regarding the license area, a proposed technical works program for the proposed license area and evidence that the applicant has the appropriate technical and financial capability.

A production license under the Petroleum Act is a statutory right which constitutes personal property. A production license (or an interest in a production license) may be transferred with the approval of the Minister and is capable of being given as security for financial accommodation or other commitments. There are processes and limits related to the Minister's ability to terminate the production license before the expiry of its term due to a default of the production license holder and the production license cannot be compulsorily acquired by the Northern Territory or the Australian Federal Government without the payment of just terms compensation to the license holder.

A production license holder has exclusive rights to explore for petroleum, recover it from the license area, and to carry out such operations in the license area as are necessary for the exploration for, and recovery of, petroleum. The Minister may grant the production license subject to such conditions as the Minister deems appropriate and may direct the holder of a production license to maintain, increase or reduce the rate of recovery of petroleum from the area.

A production license may be granted for an initial term of 21 or 25 years and may be renewed.

Retention Licenses

A retention license grants the licensee the exclusive right to carry on in the license area such geological, geophysical, and geochemical programs and other operations and works, including appraisal drilling, as reasonably necessary to evaluate the prospective resources in the license area. Where the Minister has received an application for a retention license and is satisfied that the applicant has complied with the requirements of the Petroleum Act the Minister will decide whether to grant or refuse to grant the retention license.

The initial term of a retention license is five years and may be renewed for subsequent periods, subject to the Minister's approval.

Conditions of EPs granted under the Petroleum Act

An EP is granted subject to conditions that the EP holder must comply with, including meeting minimum work obligations and conducting all operations with reasonable diligence and in accordance with good oilfield practice and the approved technical work program. Each Instrument of Grant for each of EP 76, EP 98, EP 117, EP 136, EP 143 and EP 161 contains standard conditions, including as follows:

- Condition 5 of each Instrument of Grant provides that "the permittee shall indemnify and hold indemnified at all times the Territory and its servants and agents from claims, actions, suits and demands whether debt, damages, costs or otherwise arising out of a breach of the duties and obligations, whether express or implied, of the permittee at common law, or of the Claim or of any law in force in the Territory that is applicable and whether such breach shall be that of the permittee or any of its subcontractors, servants, employees or agents";
- Condition 10 of each Instrument of Grant allows "the Minister to require, at any time, the title holder to provide security in the form and for the amount that the Minister thinks fit for the purpose of securing the title holder's performance of its obligations under the relevant EP, to secure the permittee's compliance with these permit conditions and/or for securing the payment by the permittee compensation that may be payable for the effect of the grant, renewal or variation of the permit on native title rights and interests"; and
- each Instrument of Grant also provides that "the title holder must not commence any seismic survey or drilling of a well unless the Minister is provided with the relevant details (including the geographic position of the well or area of the seismic survey) and the necessary approval has been obtained from the Minister."

Variation, suspension or waiver of a condition of an EP

An EP holder may lodge an application for a variation, suspension or waiver of a condition of an EP. Under the guidelines "Criteria for Assessment of Petroleum Exploration Permit Applications" issued by the Department of Industry Tourism and Trade ("DITT"), an application to suspend, extend, waive or vary EP conditions is required to be submitted within three months prior to expiry of the current work program year. Generally, work programs cannot be reduced by a variation. All variations are subject to the discretion of the Minister and are considered on a case-by-case basis.

An EP holder may apply to the Minister to suspend and extend the period for completing the permit holder's work program commitments.

A suspension will defer the end date of a current permit year but will not change the end date of subsequent permit years. A suspension and extension will defer the end date of the current permit year and all subsequent permit years. Where a condition of an EP is suspended the Minister may extend the term of the permit by a period not exceeding the period of the suspension. The terms of each of the EPs have previously been extended via applications to the Minister for suspension and extension of the dates for completion of the minimum work program obligations.

Ministerial approval in relation to dealings and transfers

Any instrument by which a legal or equitable interest in or affecting an existing or future EP is or may be created, assigned, affected or dealt with, whether directly or indirectly must be approved by the Minister and an entry made in the Public Register in order to be effective.

Statutory annual fees

An EP holder is required to pay an annual fee in relation to each EP. There are no outstanding annual fees payable in respect of the EPs.

Term and Renewals of the Exploration Permit

An EP remains in force for a five-year term commencing on the day on which it was granted or last renewed. An EP may be renewed for a maximum of two subsequent terms.

An application for renewal must, amongst other things, be in an approved form and manner and be accompanied by a report specifying the permittee's restoration and rehabilitation plan of the land with respect to the blocks that may be affected by the permittee's operations. The Minister will not accept an application for renewal of an EP if an application is received after expiry of the permit.

As part of the Minister's decision to renew an EP, the Minister may reduce the number of blocks in respect of which the permit is in force. If the Minister proposes to act in this way, the Minister must issue a notice to the permittee inviting the permittee to make a submission regarding the reduction (within the period specified in the notice). A title holder seeking a renewal can apply for an exemption, for a period not exceeding 12 months, from the requirement to reduce the number of blocks in a renewal application. An exemption may provide for: (a) a deferral of the reduction in the permit area; or (b) a reduction in the permit area by a lesser number of blocks.

The Minister may refuse to renew the permit where an EP holder has not complied with the Petroleum Act, any directions, or the conditions to which the EP is subject, or the Minister is not satisfied that circumstances exist to justify the renewal of the permit.

Surrender of a permit

A permittee may apply to surrender all or part of a permit area, subject to the requirements of the Petroleum Act. The Petroleum Act provides that an application for surrender of all or part of a permit area may not be made unless: (a) all operations carried on in the proposed surrender area have ceased; (b) all of the environmental outcome required under the Petroleum Act or another Act, including remediation and rehabilitation of land (including affected adjacent land), have been met; and (c) any approved environment management plan that applied in relation to the proposed surrender area ceases to be in force in relation to the proposed surrender area.

The Minister may require that further conditions be complied with before accepting a surrender, or where the Minister is satisfied that the circumstances justify the acceptance of a surrender, accept a partial surrender where the retained area is not one discrete area, or is less than the minimum allowable size.

EP Conditions

Each EP is subject to minimum work obligations. Except for EP(A) 197, each EP contains specific minimum work obligations. The minimum work obligations for EP(A) 197 will be agreed between Sweetpea and the NT Government prior to grant of the EP. The minimum work obligations in respect of the EPs that need to be completed in the near future include:

- EP 76: carrying out of formation evaluation of acquired data and integration of new core data into exploration models with estimated expenditure of A$250,000 to be completed by May 30, 2024;
- EP 98: drilling and hydraulic fracture stimulation of one horizontal exploration well to be completed by May 30, 2024 with estimated expenditure of A$20 million;
- EP 117: that between May 31, 2023 and May 30, 2025 the following work is completed with an estimated expenditure of A$30 million: (a) drilling one vertical (pilot) well and side-track one horizontal multistage fracture stimulated well; (b) formation evaluation of acquired data; and (c) further static and dynamic reservoir modelling;
- EP 136: renewal of this EP and confirmation of required minimum work obligations is pending following submission of an application to renew EP 136 dated September 28, 2023;

- EP 143: that between April 5, 2023 and April 4, 2024 the following work is completed with an estimated expenditure of A$400,000: (a) performing geological and geographical studies and integration of 2D seismic data; (b) assessing commercialization opportunities; (c) conducting desktop baseline environmental assessments; (d) preparing and commencing negotiations of land access; (e) designing and planning for 125km of 2D seismic survey;
- EP 161: that between March 21, 2023 and March 20, 2025 the following work is completed with an estimated expenditure of A$12 million: (a) acquiring processing and interpret 200km of 2D seismic data; (b) drill 2 two (2) vertical exploration wells; (c) geological and geophysical studies.

A failure to comply with these conditions may result in the Minister: (a) cancelling the permit in relation to any or all of the blocks the subject of the permit; or (b) refusing an application for renewal of the Tenement.

If these obligations are not able to be met by the required dates, the Company may be able to apply to the Minister to request that the work program be varied in accordance with the process described in the "*Variation, suspension or waiver of a condition of an EP*" section above. However, a variation may not necessarily be granted.

Overlapping Tenements

Generally, the existence of overlapping tenure in respect of the different types of resources governed by separate statutes is expected and not uncommon in the Northern Territory. The same land shares different use and may contain concurrent extraction rights. For example, Tamboran owns petroleum extraction rights in the Beetaloo, but there are also multiple pastoral leaseholders who lease the rights to graze livestock on the surface. Additionally, there are various mineral rights such as precious metal (gold, silver) and base metal (iron ore, copper, nickel) rights overlayed in the Beetaloo, along with deep geothermal rights, sand and aggregate mining rights.

The Northern Territory legislative regime does not prescribe a general order of precedence or priority of any particular form of tenure over another. Instead, there are general obligations in the *Mineral Titles Act 2010* (NT) that the holder of an EP must conduct authorized activities in relation to the title area in a way that interferes as little as possible with the rights of other occupiers of land in the vicinity of the title area. Furthermore, the *Energy Pipelines Act 1981* (NT) imposes restrictions on people undertaking certain works within the vicinity of a pipeline including crossing it with certain machinery or detonating explosives in the region. Additionally, the *Geothermal Energy Act 2009* (NT) imposes an obligation on the holders of geothermal titles to consult with the petroleum title holders before conducting geothermal activities on land that is subject to mining or petroleum titles. The Petroleum Act provides that the Minister must not grant an EP over an area that is already the subject of another EP or a license. Aside from the requirement that EPs and other petroleum permits cannot overlap, the Petroleum Act is silent on the question of overlapping tenements with respect to non-petroleum permits, other than that it provides for exclusivity of interest to the title holder. Each of our EPs were issued under the Petroleum Act. If there is any doubt as to whether an activity proposed to be carried out on the tenements will interfere with the rights of another permit holder, an appropriate consultation process will need to take place with the relevant titleholder.

Unit Development

If the Minister is satisfied that a petroleum pool extends beyond a license area and it is desirable, for the purpose of securing economy and efficiency, that the petroleum pool should be worked as one unit, the Minister may, amongst other things, require the licensee and the licensee of each adjacent area to enter into a scheme for registration under the Petroleum Act to work and develop the petroleum pool as one unit. Where a scheme is not furnished within the time specified or where the Minister does not approve the scheme furnished to him, the Minister must prepare a scheme and supply it to each permit holder and that scheme must be complied with. An agreement must be registered under the Petroleum Act in order to have effect. This type of agreement, similar to forced pooling or unitization, has not occurred for shale in Australia to date.

Access Authorities

An EP holder may apply for an access authority to conduct certain activities in an area outside the permit holder or licensee's permit area. An access authority authorizes the holder to carry on in the access authority area exploration for petroleum or operations relating to the recovery of petroleum in or from the EP, license, lease or petroleum title in respect of which the application was made and any other operations specified in the access authority.

Reserved Blocks / 'No-go zones'

A Reserved Block (also called a "no-go zone") is an area where a person cannot explore or drill for petroleum resources. These areas can include towns, parks, reserves and areas of high ecological value. Under the Petroleum Act, the Minister can declare that a block (not being a block in relation to which an EP or license is in force) will not be the subject of a grant of an EP or license. If there is a declaration in force in relation to a block, the Minister cannot grant an EP or license over the block. There are two Reserved Blocks that are located adjacent to the areas covered by EP 98 and EP 143, these include Reserved Block 200 and Reserved Block 85.

Reserved Block 200 was previously included within the area covered by EP 98. Reserved Block 200 is comprised of an area of 115.8 km2 and includes the entire area of the Bullwaddy Conservation Reserve. Reserve Block 200 has been relinquished from EP 98 and no longer forms part of this EP. The area of EP 143 includes the 2 km buffer around the Town of Newcastle Waters. The Reserved Block 85 is located within the buffer area comprising 0.238 km2 near the Town of Newcastle Waters. The buffer area near the Town of Newcastle Waters was always excluded from the area covered by EP 143.

Royalties under the Royalty Act.

Under the Royalty Act, the Company is required to pay an overriding statutory royalty to the NT Government of 10% of the gross value (net of certain expenses), at the well-head, of all petroleum produced from our assets. The gross value of that petroleum at the well-head means the sales value of the petroleum, minus the lesser of the deductible costs of the petroleum in the royalty year and the deductible cap for the petroleum for the royalty year. The costs that constitute deductible costs are post-wellhead treatment, processing, refining, storage, transport and sales costs. The deduction cap is 75% of the sales value of petroleum. Deductible costs which exceed the deduction cap can be carried forward to be deducted in future periods.

Recent Developments

See "Item 7—*Management's Discussion and Analysis of Financial Condition and Results of Operations—Recent Developments—Recent Developments*" for further information regarding our recent developments.

Available Information

The Company's website is www.tamboran.com. The Company's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, can be obtained from this site at no cost. The SEC maintains a website at www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

The Company's Corporate Governance Guidelines, Code of Business Conduct and Ethics and the charters of the Audit & Risk Management, Compensation, Nominations & Governance and Sustainability Committees are also available on the "Investor Relations" section of the Company's website at https://www.tamboran.com/corporate-governance-statements/. Copies of these documents are available in print to share owners upon request, addressed to the Corporate Secretary at the address above. The information on the Company's website is not part of this or any other report that the Company files with, or furnishes to, the SEC.

Information About our Executive Officers

In the following table, the Company sets forth certain information regarding those persons currently serving as executive officers of the Company as of September 20, 2024.

Name and Age	Position
Joel Riddle (49)	Chief Executive Officer and Director. Joel Riddle joined TR Ltd. as Chief Executive Officer in September 2013, was appointed as a Director of TR Ltd. in December 2018 and has served as Chief Executive Officer and Director of Tamboran since October 2023. Mr. Riddle brings over 25 years of experience in the upstream oil and gas industry. Prior to joining TR Ltd., Mr. Riddle served as Vice President, Commercial and Planning at Cobalt International Energy (Cobalt) from 2006 to 2013, 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 and played a role in Cobalt's initial public offering. Cobalt filed a voluntary petition for bankruptcy on December 14, 2017. Prior to his position with Cobalt, Mr. Riddle served in various management positions including business development, commercial and strategic planning with Unocal Corporation from 2002-2005 and Murphy Oil Corporation from 2005-2006. Prior to Unocal Corporation, from 2001-2002, Mr. Riddle was a senior associate with Andersen Consulting, serving upstream exploration and production clients on strategy and performance improvement engagements. Mr. Riddle began his career in 1997 as a senior reservoir engineer with ExxonMobil, serving various assignments focused on upstream oil and gas operations in the Gulf of Mexico. Mr. Riddle received a Bachelor of Science with Honors in Mechanical Engineering from the University of Florida and a Master of Business Administration from the University of Chicago. We believe Mr. Riddle is qualified to be on our board of directors due to his extensive experience with the Company and the global energy industry and his technical acumen.
Eric Dyer (42)	Chief Financial Officer. Eric Dyer joined TR Ltd. as Chief Financial Officer in November 2019 and has served as Chief Financial Officer of the Company since October 2023. Mr. Dyer has over 20 years of experience in finance in the energy, infrastructure, and sustainability sectors. Prior to joining the Company, Mr. Dyer worked at EAS Advisors LLC, a boutique investment bank in New York, from December 2010 to November 2019, where he served as Head of Energy. Prior to EAS Advisors, he served in various investment banking and capital markets roles with firms such as Atlantic-Pacific Capital, Execution LLC, IHS Markit Ltd. and RBC Capital Markets. Mr. Dyer received a Bachelor of Science in Finance from the University of Minnesota.
Faron Thibodeaux (64)	Chief Operating Officer. Faron Thibodeaux joined TR Ltd. as Chief Operating Officer in February 2021. Mr. Thibodeaux has over 40 years of technical and operations experience in the energy industry. Mr. Thibodeaux previously worked at Apache Corporation from April 2008 to November 2020, where he ultimately held the position of Vice President of Drilling, Completions and Engineering of Apache Corporation. He was also 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. Mr. Thibodeaux received a Bachelor of Science in Petroleum Engineering from the University of Louisiana at Lafayette.

ITEM 1A. RISK FACTORS

Investing in our common stock involves risks. You should carefully consider the information in this report, including the matters addressed under "Cautionary Note Regarding Forward-Looking Statements," the following risks and all of the other information set forth in this report before making an investment decision. The risks and uncertainties described below are not the only ones we face. Additional risks not presently known to us or that we currently deem immaterial may also impair our business operations. If any of the following risks actually occur, our business, financial condition and results of operations could be materially and adversely affected, and we may not be able to achieve our goals. We cannot assure you that any of the events discussed in the risk factors below will not occur. The trading price of our common stock could decline due to any of these risks, and you may lose all or part of your investment.

Risks Related to Our Business and Industry

We are an early stage development company with no material revenue expected until 2026, at the earliest. We have a limited operating history, and our future performance is uncertain. Our ability to successfully drill and complete the wells identified for our current capital plan will depend on a variety of factors.

We are an early stage development company with no material revenues or reserves currently. To date we have drilled and completed only four wells as operator. We have observed lower normalized flow rates in one well compared to other wells that we have participated in drilling in the Beetaloo. We currently only have one well that we believe based on initial flow rates is a productive well, meaning it is capable of producing sufficient quantities of gas to justify completion. Companies in the early stages of operations face substantial business risks and may suffer significant losses. We face challenges and uncertainties in financial planning as a result of the unavailability of historical data and uncertainties regarding the nature, scope and results of our future activities. In the event that our drilling program is delayed, our operating results will be adversely affected, and our operations will differ materially from the activities described in this report.

Our business strategy includes importing and successfully utilizing U.S. drilling and completion techniques to the Northern Territory. We may not be successful in implementing that strategy or in completing the development of the infrastructure necessary to conduct our business as planned. Our ability to successfully maximize the benefits of U.S. technology and techniques depends on a variety of factors, including avoiding delays in procuring equipment and the ability to attract and train employees qualified to operate with U.S. best practices. As a result, we cannot assure you that we will achieve a rate of drilling success that is in line with, or even comparable to, expectations for natural gas development in the United States.

Our business plan requires substantial additional capital, which we may be unable to raise on acceptable terms in the future, or at all, which may in turn limit our ability to execute on our plans.

We have working interests in six additional wells that we plan to drill through calendar year 2025, and estimate gross expenses of approximately $26 million to drill and complete each of those wells. Our ability to raise the capital required to fund the various phases of our development plan will depend on many factors, including:

- our success in attracting third party strategic and financial partners and investors to significantly fund our midstream and LNG terminal development goals;
- the scope, rate of progress and cost of our development activities;
- natural gas prices;
- our ability to produce natural gas from our properties;
- the terms and timing of any drilling and other production-related arrangements that we may enter into;
- the infrastructure available and developed near our properties;

- the cost and timing of governmental approvals and/or concessions; and
- the effects of competition by other companies operating in the oil and natural gas industry.

We do not currently have any commitments for future external funding, and we do not expect to generate any revenue from production until 2026, at the earliest, which will depend upon successful drilling results, additional and timely capital funding, further regulatory approvals, and access to suitable infrastructure. Additional financing may not be available on favorable terms, or at all. Even if we succeed in selling additional securities to raise funds, at such time the ownership percentage of our existing stockholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing stockholders. If we raise additional capital through debt financing, the financing may involve covenants that restrict our business activities. If we choose to farm-out interests in our property, we may lose operating control over such property.

In addition, limitations on new share issuances under ASX rules may limit or prevent us from raising additional capital by issuing and selling shares of common stock or other securities when such additional capital is required. See "*Our ability to raise additional capital may be significantly limited by listing rules of the ASX that limit the amount of common stock that we are permitted to issue without stockholder approval*."

Our business plan contemplates delivering natural gas to the Northern Territory, the Australian East Coast as well as select markets in South and East Asia. Our ability to deliver natural gas in significant quantities to these markets depends on the construction of additional pipeline capacity. We cannot assure you that we will be able to secure sufficient take-away capacity on our timing or at all.

The anticipated production from our business plan will exceed the capacity of the existing pipeline infrastructure that services the Beetaloo. Although we have preliminary agreements with APA Group whereby APA Group has agreed to evaluate the joint development and construction of two additional pipelines from the Beetaloo, any construction of additional pipelines is subject to the execution of mutually satisfactory definite documentation and the satisfaction of several conditions precedent. APA Group has no obligation to construct or dedicate funds to the construction of a pipeline, and may decline to proceed with construction. We cannot assure you that we will reach a mutually satisfactory agreement with APA Group for the construction of the required take-away capacity or the satisfaction to the conditions of any such obligation. The failure to contract for the construction of additional take-away capacity will adversely affect the ability to execute our proposed business plan. In addition, even if we are able to contract for sufficient take-away capacity, we may not be able to contract for gathering and compression services, storage facility capacity, and interconnections to the major pipelines.

We have no proved reserves at this time and areas that we decide to drill may not yield natural gas in commercial quantities or quality, or at all.

We presently have no proved reserves and have not sold any natural gas produced. Based on petrophysical analysis, we have identified locations and drilled appraisal wells that indicate prospective resources. However, our appraisal wells may not be indicative of future results. Additionally, the areas we have drilled, or may decide to drill in the future, may not yield natural gas in commercial quantities or quality, or at all. All of our current property is undeveloped and in various stages of evaluation that will require substantial additional seismic data reprocessing and interpretation. Accordingly, we do not know if our properties will contain natural gas in sufficient quantities or quality to recover drilling and completion costs or to be economically viable. Even if natural gas is found on our property in commercial quantities, construction costs of natural gas pipelines, associated infrastructure, and transportation costs may prevent such property from being economically viable.

Additionally, the analogies drawn by us from available data from other wells may not prove valid in respect of additional wells on our property. If a significant portion of our property does not prove to be successful, our business, financial condition and results of operations will be materially adversely affected.

We face substantial uncertainties in estimating the characteristics of our property, so you should not place undue reliance on any of our estimates.

In this report, we provide estimates of the characteristics of our properties, such as implied production volumes (including our 2.0 Bcf/d gross production goal and the normalization of initial production rates to longer lateral lengths), in the Beetaloo. These estimates may be incorrect, as the accuracy of these estimates is a function of the available data, geological interpretation and our judgment. We may not achieve our 2.0 Bcf/d gross production goal on our proposed timeline or at all, and the wells we have drilled or will drill may not achieve ultimate recoveries within the ranges we have estimated. To date, only four wells on our property have been drilled with us as an operator. Any analogies drawn by us from other wells or producing fields may not prove to be accurate indicators of the success of developing reserves from our property. Furthermore, we have no way of evaluating the accuracy of the data from analog wells or properties produced by other parties that we may use. Any significant variance between actual results and our assumptions could materially affect the quantities of natural gas attributable to any particular group of properties.

Drilling wells is speculative, often involving significant costs that may be more than our estimates, and may not result in any discoveries or additions to our future production or reserves. Any material inaccuracies in drilling costs, estimates or underlying assumptions will materially affect our business.

Exploring for and developing natural gas reserves involves a high degree of operational and financial risk, which precludes definitive statements as to the time required and costs involved in reaching certain objectives. The budgeted costs of drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise due to a tightening in the supply of various types of natural gas field equipment and related services. Drilling may be unsuccessful for many reasons, including geological conditions, weather, cost overruns, equipment shortages and mechanical difficulties. Exploratory and appraisal wells bear a much greater risk of loss than development wells. Moreover, the successful drilling of a natural gas well does not necessarily result in a profit on investment.

Following the stimulation of the A2H well in EP 98, which is the first Beetaloo well that we drilled and completed, we observed lower normalized flow rates than other wells we have participated in the drilling of in the Beetaloo. Laboratory testing of the recovered fluid identified a zone of reduced permeability, or a “skin,” which created an impediment to the flow of natural gas. A variety of factors, both geological and market-related, can cause a well to become uneconomic or only marginally economic. Our initial drilling sites, and any potential additional sites that may be developed, require significant additional exploration and development, regulatory approval and commitments of resources prior to commercial development. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our business operations as proposed and would be forced to modify our plan of operation.

We intend to import and implement U.S. practices and technology for use in the development of our properties in the Northern Territory. There is limited experience with these practices and technology within the workforce in the areas we operate. The ability to attract and train a qualified workforce could hamper our present operations and limit our ability to grow.

Our operations are mechanically complex and must be performed in remote geographic locations. We believe that our success depends upon our ability to employ and retain a sufficient number of technical personnel who have the ability to utilize, enhance and maintain our natural gas development equipment. Our ability to maintain and expand our operations depends in part on our ability to utilize, replace, supplement and increase our skilled labor force. The supply of skilled workers is limited in the Beetaloo, and it is not guaranteed that we will be able to access a sufficient skilled labor force. A significant increase in the wages paid by competing employers domestically and abroad could result in a reduction of our skilled labor force or cause an increase in the wage rates that we must pay or both. Employee turnover may also lead to lost productivity and decrease employee engagement which could adversely impact our business.

Additionally, our ability to hire, train and retain qualified personnel may become more challenging as we grow and to the extent energy industry market conditions are competitive. Our ability to successfully implement U.S. practices and technology is dependent on finding, training and retaining qualified personnel within Australia for work in the Northern Territory. When general industry conditions are favorable, the competition for experienced operational and field technicians increases as other energy and manufacturing companies' needs for the same personnel increases. Our ability to grow or even to continue our current level of operations could be adversely impacted if we are unable to successfully hire, train and retain these important personnel. In addition, effective succession planning for our employees and expansion planning is important to our long-term success. Failure to achieve these plans could hinder our strategic planning and execution and have a material adverse impact on our business, financial condition or results of operations.

Our inability to access appropriate equipment and infrastructure in a timely manner may hinder our access to natural gas markets and delay the phases of our business plan.

Our ability to market our natural gas will depend substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties not within our control. Our failure to obtain such services on acceptable terms could materially harm our business. The success of our business plan depends on importing and implementing U.S. practices and technology for use in the development of our properties in the Northern Territory. We have not yet secured importing contracts. The delivery of the further drilling rigs may be delayed or cancelled, and we may not be able to gain continued access to suitable rigs in the future. We may be required to shut in natural gas wells because of the absence of a market or because access to pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until arrangements were made to deliver the production to market, which could cause significant delays to the phases of our business plan and have a material adverse effect on our results of operations and financial condition.

In the Beetaloo, as our development is in its preliminary stage, we have no binding agreements for the gathering and processing of our potential future production. As a result, our business plan is dependent on third parties to develop the infrastructure for our natural gas gathering needs. Capital constraints could limit the construction of new pipelines and gathering systems. Until this new capacity is available, we may experience delays in producing and selling our natural gas. In such event, we might have to shut in our wells while awaiting a pipeline connection or additional capacity, which would adversely affect our results of operations. Even when available, the ultimate costs of gathering and transportation systems may prevent some of our properties from being economically viable.

A portion of our natural gas production may be interrupted, or shut in, from time to time for numerous reasons, including weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could materially adversely affect our cash flow.

Drilling, completions, workover and hydraulic fracturing operations are operationally complex activities which present certain risks that could adversely affect our business, financial condition or results of operations.

In our drilling operations, from time to time we experience certain issues and encounter risks, including, for example, mechanical and instrument or tool failures; drilling difficulties associated with drilling in swelling clay or shales and unconsolidated formation; wellbore instability and other geological hazards; loss of well control and associated hydrocarbon release and/or natural gas clouds; loss of drilling fluids circulation; surface spills of various drilling or well fluids; subsurface collision with existing wells; proximity of adjacent water wells or aquifers; inability to establish drilling fluid circulation; loss or compromise of drill pipe or casing integrity; surface pumping operations and associated pressure and hydrocarbon hazards; stuck and lost-in-hole tools, drill pipe or casing; large drilling equipment and machinery including electrical hazards; insufficient cementing of casing causing unwanted casing pressure or fluid migration; surface overpressure events from large machinery (horsepower), equipment or well pressure; fines and violations related to relevant laws and regulations; fires and explosions; personnel safety hazards such as working at heights, driving or equipment operation, energy isolation, excavation and trenching and more; structural damage and collapse to large equipment and machinery; major damage or malfunction to key equipment or processes; in certain instances, close proximity of operations to residences and/or communities; among other typical shale basin drilling challenges and risks.

In our hydraulic fracturing, workover and completions activities, from time to time we experience certain issues and encounter risks, including, for example, mechanical and instrument or tool failures; loss of well control and associated hydrocarbon release and/or natural gas clouds; well kick or flowback during completion or fracturing operations; lost or stuck in hole wireline, coiled tubing or workover strings and tools; loss or compromise of workover string, tubing or casing integrity; large completions, wireline, coiled tubing and workover rig equipment and machinery including electrical hazards; insufficient cementing of casing causing unwanted casing pressure or fluid migration while fracturing or thereafter; proximity of adjacent water wells or aquifers and adjacent producing wells; surface spills of various fracturing, freshwater or well fluids or chemicals; surface pumping and flowback operations and associated pressure and hydrocarbon hazards; surface overpressure events from large machinery (horsepower), equipment or well pressure; fines and violations related to relevant laws and regulations; fires and explosions; personnel safety hazards such as working at heights, driving or equipment operation, energy isolation, excavation and trenching and more; structural damage and collapse to large equipment and machinery; major damage or malfunction to key equipment or processes; in certain instances, close proximity of operations to residences and/or communities; among other typical fracturing, workover and completion challenges and risks.

Our industry requires us to navigate many uncertainties that could adversely affect our financial condition and results of operations.

Our financial condition and results of operations depend on the success of the development of our assets, which are subject to numerous risks beyond our control, including the risk that development will not result in commercially viable production or uneconomic results or that various characteristics of the drilling process or the well will cause us to abandon the well prior to fully producing commercially viable quantities.

Our actual development cost for a well could significantly exceed planned "authorization for expenditure" levels. Further, many factors may curtail, disrupt, delay or cancel our scheduled drilling projects and ongoing operations, including the following:

- reductions of sustained declines in natural gas prices; and
- regulatory compliance, including limitations on wastewater disposal, discharge of greenhouse gases and hydraulic fracturing.

In addition, our assets are anticipated to be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, the scope, rate of progress and cost of our exploration and production activities. Our ability to drill and develop our assets depends on a number of factors, including the availability of equipment and capital, seasonal conditions, regulatory approvals, obtaining land access agreements for regulated operations, natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if our properties will be drilled within our expected timeframe or at all or if we will be able to economically produce natural gas from these or any other potential drilling locations. As such, our actual drilling activities may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

Natural gas prices are volatile. A reduction or sustained decline in prices may adversely affect our business, financial condition or results of operations and our ability to meet our financial commitments or raise capital.

Our future growth is dependent on the continued economic importance of the natural gas development and production industry in Australia and global demand (as it relates to LNG trade). Any substantive and prolonged changes to the current economic importance of natural gas development and production industry in Australia would be likely to have an adverse effect on our business, financial condition and profits.

Prevailing natural gas prices heavily influence our potential revenue, profitability, access to capital, growth rate and value of our properties. Further, although we do not produce oil, to the extent oil prices rise considerably, the cost of services we incur may also increase. As a commodity, natural gas prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the natural gas market has been volatile. Our revenue, profitability and future growth are highly dependent on the prices we receive for our natural gas production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but not limited to, the following:

- worldwide and regional economic conditions impacting the global supply of and demand for natural gas, including economic growth expectations, inflation and hostilities in Ukraine and the Middle East;
- the actions of OPEC, its members and other state-controlled oil companies relating to oil price and production controls;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- prevailing prices on local price indexes in the areas in which we operate and expectations about future commodity prices;
- extent of natural gas production associated with increased oil production;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- weather conditions across the globe;
- technological advances affecting energy consumption;
- speculative trading in natural gas markets;
- end-user conservation trends;
- petrochemical, fertilizer, ethanol, transportation supply and demand balance;
- the price and availability of alternative fuels;
- domestic, local and foreign governmental regulation and taxes; and
- liquefied petroleum products supply and demand balances.

In particular, because of our higher operating costs than U.S. producers, our business model is dependent on the higher natural gas prices we receive from Asian and domestic Australian markets relative to U.S. prices. If commodity prices decrease or we experience widening of basis differentials, our cash flows and refinancing ability will be reduced. We may be unable to obtain needed capital or financing on commercially reasonable terms. Lower commodity prices may also reduce the amount of natural gas that we can produce economically. Additionally, a significant portion of our projects could become uneconomic and require us to abandon or postpone our planned drilling. As a result, a reduction or sustained decline in natural gas prices may materially and adversely affect our financial condition, results of operations, liquidity and our ability to finance capital expenditures.

We may not be able to manage our future growth effectively, which could make it difficult to execute our business strategy.

Our expected future growth could create a strain on the organizational, administrative and operational infrastructure. Our ability to manage our growth effectively will require us to continue to improve our operational, financial and management controls, as well as reporting systems and procedures. Our current team is small, and we will have to hire additional employees to achieve our expected future growth. Our business strategy will be difficult to execute, which may impact our ability to effectively attract employees. As we grow, any failure of our controls or interruption of our facilities or systems could have a negative impact on our business and financial operations. Our future development plan, including the potential development of pipelines, and LNG export facility, will affect a broad range of business processes and functional areas. The time and resources required to implement these new extensions of our business are uncertain, and failure to complete these activities in a timely and efficient manner could adversely affect our operations. If we are unable to manage growth effectively, it may be difficult for us to execute our business strategy.

Our business plan contemplates the execution of midstream contracts with certain third parties in order to allow us to supply our own natural gas to the Northern Territory, the Australian East Coast, and/or for export out of Darwin. We cannot assure you that we will be successful in obtaining the commercial contracts necessary to facilitate direct delivery of our natural gas production on commercially reasonable terms, or at all.

We cannot assure you that we will succeed in any effort to establish midstream contracts that would allow us to supply our own natural gas for export out of Darwin or directly to the Australian East Coast. Even when the physical infrastructure exists to supply our own natural gas directly to Darwin and the Australian East Coast, our ability to utilize that infrastructure depends on whether we can successfully negotiate and enter into midstream contracts on commercially reasonable terms or at all. If we fail to enter into such contracts on commercially reasonable terms or at all or are otherwise subject to capacity constraints, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Construction of midstream projects subjects us to risks of construction delays, cost over-runs, limitations on our growth and negative effects on our financial condition, results of operations, cash flows and liquidity.

The second and third phase of our business requires the construction of midstream projects, including pipelines to access the East Coast and our proposed NTLNG terminal, some of which may take a number of years before commercial operation. These projects are complex and subject to a number of factors beyond our control, including delays from third-party landowners, the permitting process, government and regulatory approval, compliance with laws, unavailability of materials, labor disruptions, environmental hazards, financing, accidents, weather and other factors. Any delay in the completion of these projects could have a material adverse effect on our financial condition, results of operations, cash flows and ability to pay dividends on our common stock. The construction of these midstream facilities requires the expenditure of significant amounts of capital, which may exceed our estimated costs. Estimating the timing and expenditures related to these development projects is very complex and subject to variables that can significantly increase expected costs. Should the actual costs of these projects exceed our estimates, our liquidity and financial condition could be adversely affected. This level of development activity requires significant effort from our management and technical personnel and places additional requirements on our financial resources and internal financial controls. We may not have the ability to attract and/or retain the necessary number of personnel with the skills required to bring complicated projects to successful conclusions.

The construction of midstream projects also requires the support of third-party strategic partners, who may have differing goals and strategies. If our strategic partners do not cooperate in the construction of the midstream projects, we may be unable to market our future natural gas production.

If our assessments of the Beetaloo are materially inaccurate, it will have a fundamental impact on our business.

Our assessment of our property may be inherently inexact and may be inaccurate, including the following:

- the time it takes to bring the Beetaloo to commercial development phase;

- the amount of recoverable reserves;
- timing of development of takeaway capacity and access to other infrastructure, including LNG terminals, on an economically viable basis;
- geological complexity;
- applicable governmental rules and regulations;
- native title holders and traditional Aboriginal owners;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessments will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the breadth of the territory we hold license to in order to assess fully their capabilities and deficiencies. We plan to undertake further development of our properties through the use of cash flow from existing production. Therefore, a material deviation in our assessments of these factors could result in less cash flow being available for such purposes than we presently anticipate, which could either delay future development operations (and delay the anticipated conversion of reserves into cash), or cause us to seek alternative sources to finance development activities.

Numerous uncertainties exist in estimating quantities of proved and possible reserves and any such estimates may be inaccurate.

Reserve engineering is a process of estimating commercially recoverable amounts of petroleum that remain in known accumulations that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In estimating probable reserves, it should be noted that those reserve estimates inherently involve greater risk and uncertainty than estimates of proved reserves. Any estimates of proved and probable reserves presented in this report have not been adjusted for risk due to their uncertainty of recovery and are not comparable to measures of proved and probable reserves that we or any other company may provide. In addition, amounts of proved and probable reserves provided by us or any other company should not be summed into total amounts due to the aforementioned uncertainties.

We are dependent on certain members of our management and technical team.

Investors in our common stock must rely upon the ability, expertise, judgment and discretion of our management and the success of our technical team in developing our future natural gas reserves. Our performance and success are dependent, in part, upon key members of our management and technical team, and their loss or departure could be detrimental to our future success. In making a decision to invest in our common stock, you must be willing to rely to a significant extent on our management's discretion and judgment. There can be no assurance that our senior management will remain in place. The loss of any of our management and technical team members could have a material adverse effect on our results of operations and financial condition, as well as on the market price of our common stock.

We have limited control over properties and investments operated by others or through joint ventures.

Certain of our properties are operated by other companies and may involve third-party working interest owners. We have limited influence and control over the operation or future development of such properties and investments, including compliance with environmental, health and safety regulations or the amount and timing of required future capital expenditures. In addition, we conduct certain of our operations through joint ventures in which we may share control with third parties, and the other joint venture participants may have interests or goals that are inconsistent with those of the joint venture or us. These limitations and our dependence on such third parties could result in unexpected future costs or liabilities and unplanned changes in operations or future development, which could adversely affect our financial condition and results of operations.

Our financial performance is subject to our counterparties' or joint venture partners' performance of their obligations under the relevant contracts, including the joint venture agreements. If one of our counterparties or joint venture partners fails to perform its contractual obligations, it may result in loss of earnings, termination of other related contracts, disputes and/or litigation that could impact our financial performance.

Currently, we are not the operator of EP 161, which is operated by Santos. As we carry out our exploration and development programs, we may enter into arrangements with respect to existing or future properties that result in a greater proportion of our properties being operated by others. As a result, we may have limited ability to exercise influence over the operations of the properties operated by our partners. Dependence on the operator could prevent us from realizing our target returns for those properties. Further, it may be difficult for us to pursue one of our key business strategies of minimizing the cycle time between discovery and initial production with respect to properties for which we do not operate. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations of some of our properties may cause a material adverse effect on our results of operations and financial condition.

All of our assets and operations are located in the Beetaloo, making us vulnerable to risks associated with operating in one geographic area.

Our operations are geographically concentrated in the Northern Territory of Australia, and specifically the Beetaloo. As a result, we may be disproportionately exposed to the impact of regional supply and demand factors in the Beetaloo caused by significant governmental regulation, curtailment of production or interruption of the processing or transportation of natural gas produced from wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within a specific geographic natural gas producing area such as the Beetaloo, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our operations, we could experience any of the same conditions at the same time, resulting in a relatively greater impact on our revenue than they might have on other companies that have more geographically diverse operations.

Our business is subject to operating hazards that could result in substantial losses or liabilities for which we may not have adequate insurance coverage.

Natural gas operations are subject to many risks, including well blowouts, craterings, explosions, uncontrollable flows of natural gas or well fluids, fires, pipe, casing or cement failures, abnormal pressure, pipeline leaks, ruptures or spills, vandalism, pollution, releases of toxic gases, adverse weather conditions or natural disasters and other environmental hazards and risks. If any of these hazards occur, we could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- investigatory, monitoring, and cleanup responsibilities;
- regulatory investigations and penalties or lawsuits;
- loss of, or delay in revenue;
- suspension or impairment of operations; and
- repairs to resume operations.

We maintain insurance against some, but not all, potential losses or liabilities arising from our operations in accordance with what we believe are customary industry practices and in amounts and at costs that we believe to be prudent and commercially practicable. Our insurance includes deductibles that must be met prior to recovery, as well as sub-limits and/or self-insurance. Additionally, our insurance is subject to exclusions and limitations. Our insurance does not cover every potential risk associated with our operations, including the potential loss of significant revenues. We can provide no assurance that our coverage will adequately protect us against liability from all potential consequences, damages and losses.

We maintain insurance coverage that is considered appropriate for a company of our size operating in the gas exploration phase, subject to policy terms and conditions. This includes insurance coverage related to general and product liability, property, workers compensation, cyber, terrorism and malicious acts, operator’s extra expenses for control of well, seepage and pollution, cleanup and contamination, evacuation expenses and making the well safe.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. Some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable, and we may elect to maintain minimal or no insurance coverage. If we incur substantial liability from a significant event and the damages are not covered by insurance or are in excess of policy limits, then we would have lower revenues and funds available to us for our operations, that could, in turn, have a material adverse effect on our business, financial condition and results of operations.

Additionally, we will rely to a large extent on transportation infrastructure owned and operated by third parties and damage to, or destruction of, those third-party infrastructure will affect our ability to process, transport and sell our production.

We are subject to numerous risks inherent to the exploration and production of natural gas.

Natural gas exploration and production activities involve many risks that a combination of experience, knowledge and careful evaluation may not be able to overcome. Our future success will depend on the success of our exploration and production activities and on the future existence of the infrastructure that will allow us to take advantage of our findings. Additionally, our natural gas properties are located in an area without significant existing infrastructure, which generally increases the capital and operating costs, technical challenges and risks associated with natural gas exploration and production activities. As a result, our natural gas exploration and production activities are subject to numerous risks, including the risk that drilling will not result in commercially viable natural gas production. Our decisions to purchase, explore, develop or otherwise exploit properties will depend in part on the evaluation of seismic data through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations.

Furthermore, the marketability of expected natural gas production from our property will also be affected by numerous factors. These factors include, but are not limited to, market fluctuations of prices, proximity, capacity and availability of pipelines, the availability of processing facilities, equipment availability and government regulations (including, without limitation, regulations relating to prices, taxes, royalties, allowable production, importing and exporting of natural gas, environmental protection and climate change). The effect of these factors, individually or jointly, may result in us not receiving an adequate return on invested capital.

In the event that our drilling programs are developed and become operational, they may not produce natural gas in commercial quantities or at the costs anticipated, and our projects may cease production, in part or entirely, in certain circumstances. Drilling programs may become uneconomic as a result of an increase in operating costs to produce natural gas. Our actual operating costs may differ materially from our current estimates. Moreover, it is possible that other developments, such as increasingly strict environmental, health and safety laws and regulations and enforcement policies thereunder and claims for damages to property or persons resulting from our operations, could result in substantial costs and liabilities, delays, an inability to complete our drilling programs or the abandonment of such drilling programs, which could cause a material adverse effect on our results of operations and financial condition.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has identified and scheduled drilling locations on our acreage over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of equipment and capital, seasonal conditions, regulatory approvals, natural gas prices, costs and drilling results. The final determination on whether to drill any of these drilling locations will be dependent upon the factors described above as well as, to some degree, the results of our drilling activities with respect to our appraisal wells. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe or at all. As such, our actual drilling activities may be materially different from our current expectations, which could adversely affect our results of operations and financial condition.

The development schedule of natural gas projects, including the availability and cost of drilling rigs, equipment, supplies, personnel and natural gas field services, is subject to delays and cost overruns.

Historically, some natural gas projects have experienced delays and capital cost increases and overruns due to, among other factors, the unavailability or high cost of drilling rigs and other essential equipment, supplies, personnel and natural gas field services. The cost to develop our projects has not been fixed and remains dependent upon a number of factors, including the completion of detailed cost estimates and final engineering, contracting and procurement costs. Our construction and operation schedules may not proceed as planned and may experience delays or cost overruns. Any delays may increase the costs of the projects, requiring additional capital, and such capital may not be available in a timely and cost-effective fashion.

Part of our business strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Difficulties that we face while completing our wells include:

- the ability to fracture stimulate the planned number of stages with the planned amount of proppant;
- the ability to run tools through the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production. If our development and production results are less than anticipated, the return on our investment for a particular well may not be as attractive as we anticipated, and its value could decline in the future.

We also may be subject to additional costs or shortages of equipment and labor because of the necessity of importing certain equipment or hiring talent from the United States. The unavailability or high cost of drilling rigs, completion crews, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.

Shale gas completions require significant amounts of water which is subject to delays in regulatory approval from certain aquifers and the cost of utilization of aquifer water may increase over time.

The demand for drilling rigs, completion crews, pipe and other equipment and supplies, including sand and other proppant used in hydraulic fracturing operations and acid used for stimulation can fluctuate significantly, often in correlation with commodity prices or drilling activity in our area of operation and in other shale basins, causing periodic shortages of supplies and needed personnel and rapid increases in costs. Increased drilling activity could materially increase the demand for and prices of these goods and services, and we could encounter rising costs and delays in or an inability to secure the personnel, equipment, power, services, resources and facilities access necessary for us to conduct our drilling and development activities, which could result in production volumes being below our forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs could have a material adverse effect on our future cash flow and profitability.

Our recurring losses from operations, negative cash flows and substantial cumulative net losses raise substantial doubt about our ability to continue as a going concern.

In Note 1 titled “Nature of the Organization and Business” of our audited consolidated financial statements for fiscal years 2023 and 2024 included elsewhere in this report, we disclose that there is substantial doubt about our ability to continue as a going concern. In addition, our independent registered public accounting firm included an explanatory paragraph in its report on our consolidated financial statements for fiscal years 2023 and 2024, which stated that there are factors that raise substantial doubt on our ability to continue as a going concern. We have incurred significant operating losses and negative cash flows from operations and expect to continue incurring increasing losses for the foreseeable future as we further our development program. Further, we had accumulated deficit of $108.5 million as of June 30, 2023 and $130.4 million as of June 30, 2024. These conditions raise substantial doubt about our ability to continue as a going concern. Our consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Our ability to become a profitable operating company is dependent upon our ability to generate revenue and obtain financing adequate to fulfill our development and commercialization activities, and achieving a level of revenue adequate to support our cost structure. We have plans to obtain additional resources to fund our currently planned operations and expenditures through additional debt and equity financing, however, there is no guarantee we obtain financing at all or on commercially acceptable terms. We may not continue as a going concern if we do not raise additional capital. We believe that the proceeds raised from the private placement of our CDIs in December 2023 and January 2024 provide us with the capital necessary to continue as a going concern through fiscal year 2024, and the amount of proceeds from our IPO, together with our existing cash on hand and future capital raising, will be sufficient to fund our planned drilling and testing program at least through the end of fiscal year 2025. Our plans are substantially dependent upon the success of commercial production at the Beetaloo, which is still in the early stages of development, and are dependent upon, among other things, the success of our drilling program and infrastructure development in the Beetaloo. If we are unable to obtain sufficient funding, our financial condition and results of operations will be materially and adversely affected, and we may be unable to continue as a going concern. Future financial statements may disclose substantial doubt about our ability to continue as a going concern. If we seek additional financing to fund our business activities in the future and there remains substantial doubt about our ability to continue as a going concern, investors or other financing sources may be unwilling to provide additional funding to us on commercially reasonable terms or at all.

Our long-term business plan contemplates the development of an additional LNG export terminal on the northern coast of Australia. Our ability to develop such a facility is dependent on our ability to attract a third-party partner as well as securing the necessary permits.

We anticipate commencing construction of the NTLNG project as early as 2027 with completion occurring as early as 2030. Our ability to commence construction of the NTLNG project on schedule is dependent on a number of factors outside of our control, including the willingness of potential third-party partners to commit to the project. Although we have entered into memoranda of understanding with subsidiaries of each of bp and Shell with respect to long-term contracts for the purchase of a total of 4.4 Mtpa from the NTLNG project, these memoranda of understanding are not binding obligations of bp or Shell and either may decide not to pursue our project. We cannot assure you we will be successful in the negotiating or execution of definitive agreements. Failure to do so could cause significant delays to the phases of our business plan and have a material adverse effect on our results of operations and financial condition.

A financial crisis or deterioration in general economic, business or industry conditions could materially adversely affect our results of operations and financial condition.

Concerns over global economic conditions, stock market volatility, energy costs, geopolitical issues, inflation and U.S. Federal Reserve interest rate increases and elevated high interest rate in response, the availability and cost of credit, and slowing of economic growth in the United States and fears of a recession have contributed and may continue to contribute to economic uncertainty and diminished expectations for the global economy.

As a result of inflation, we experienced supply chain constraints and inflationary pressure on our cost structure throughout fiscal years 2023 and 2024. Principally, commodity costs for steel and chemicals required for drilling, higher transportation and fuel costs and annual wage increases have increased our operating costs for fiscal year 2024 compared to fiscal year 2023. We cannot predict the future inflation rate but to the extent inflation remains elevated and supply chain constraints remain, we may experience cost increases in our operations, including costs for drill rigs, workover rigs, hydraulic fracturing fleets, tubulars and other well equipment, as well as increased labor costs. Some supply chain constraints and inflationary pressures could persist into fiscal year 2025 but are expected to plateau, however we cannot accurately predict future supply chain constraints and inflation. If we are unable to manage our supply chain, our ability to procure materials and equipment in a timely and cost-effective manner, if at all, may be negatively impacted, which could materially adversely impact our results of operations and financial condition.

Similarly, we cannot predict the impact that high market volatility and instability in the banking sector could have on economic activity and our business in particular. The failure of banks and financial institutions and measures taken, or not taken, by governments, businesses and other organizations in response to these events could adversely impact our business, financial conditions and results of operations.

In addition, continued hostilities between Russia and Ukraine, the conflict between Israel and Hamas, other hostilities in the Middle East, and the occurrence or threat of terrorist attacks in Australia or other countries could adversely affect the economies of Australia and other countries. The ongoing conflict in Ukraine and Israel could continue to have repercussions globally by continuing to cause uncertainty, not only in the natural gas markets, but also in the capital markets. Such uncertainty could result in stock price volatility and supply chain disruptions, as well as higher natural gas prices which could potentially result in increased inflation worldwide and could negatively impact demand for natural gas, NGLs, oil and electricity.

Concerns about global economic growth can result in a significant adverse impact on global financial markets and commodity prices. In addition, any financial crisis may cause us to face limitations on our ability to access the debt and equity capital markets and complete asset purchases or sales.

Further, if there is a financial crisis or the economic climate in Australia or abroad deteriorates, worldwide demand for hydrocarbon-based products could materially decrease, which could impact the price at which natural gas from our properties are sold, affect the ability of vendors, suppliers and service providers associated with our properties to continue operations and ultimately materially adversely impact our results of operations, financial condition and ability to pay dividends on our common stock.

Events outside of our control, including an epidemic or outbreak of an infectious disease, terrorism, geopolitical instability, and security threats, could have a material adverse effect on our business, liquidity, financial condition, results of operations, and/or cash flows.

We face risks related to pandemics, epidemics, outbreaks or other public health events, or the threat thereof, that are outside of our control, and could significantly disrupt our business and operational plans and adversely affect our liquidity, financial condition, results of operations, cash flows and ability to pay dividends on our common stock.

The nature, scale and scope of the above-described events, combined with the uncertain duration and extent of governmental actions, prevent us from identifying all potential risks to our business. We believe that the known and potential impacts of pandemic-related events include, but are not limited to, the following:

- disruption in the demand for natural gas, NGLs and oil and other petroleum products;
- intentional project delays until commodity prices stabilize;
- a potential future downgrade of our credit rating and potentially higher borrowing costs in the future;
- a need to preserve liquidity, which could result in reductions, delays or changes in our capital expenditures;
- supply chain and shipping lane disruptions, resulting in shortages of, and increased pricing pressures on, among other things, equipment, services and labor;
- liabilities resulting from operational delays due to decreased productivity resulting from stay-at-home orders affecting our workforce or facility closures;
- future asset impairments, including impairment of our natural gas properties and other property and equipment; and
- infections and quarantining of our employees and the personnel of vendors, suppliers and other third parties.

A terrorist attack or armed conflict targeting our systems or natural gas infrastructure generally could materially adversely impact our operations.

Growing geopolitical instability and armed conflicts (including the armed conflict between Russia and Ukraine and between Israel and Hamas as well as other hostilities in the Middle East) has resulted in energy infrastructure becoming a more prominent target of attack by terrorists and conflicting countries. Natural gas, NGLs and oil related facilities, including those operated by us or our service providers, could be direct targets of physical or cyber-attacks, and, if infrastructure integral to our operations is destroyed or damaged, we may experience a significant disruption in our operations. Any such disruption could materially adversely affect our financial condition, results of operations and cash flows. Costs for insurance and other security may increase as a result of increased threats, and certain insurance coverage may become more difficult to obtain, if available at all.

Our business could be negatively affected by security threats and disruptions, including electronic, cybersecurity or physical security threats, incidents and other disruptions.

Our business faces various security threats, including cybersecurity risks that threaten the confidentiality, integrity and availability of our IT systems and information (including personal, confidential and other types of sensitive information); threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts, civil unrest and similar acts. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security threats, incidents or disruptions from occurring. Security incidents could lead to losses of sensitive information, critical infrastructure or capabilities essential to our operations, or otherwise impact the availability, integrity or confidentiality of our IT systems and sensitive information, and could have a material adverse effect on our reputation, financial position, results of operations and cash flows.

In relation to information technology and cybersecurity, an initial risk assessment was undertaken in early 2024 and the results have been presented to the Audit & Risk Management Committee. As part of this risk assessment, we completed a cybersecurity maturity assessment using the Cybersecurity Framework developed by U.S. National Institute of Science and Technology and have started to take steps intended to address certain findings from these assessments.

However, although we plan to implement, and our third-party vendors and suppliers may implement, various controls, systems and processes intended to secure these information systems, there can be no assurance that our efforts will be effective in protecting our IT systems, facilities, infrastructure and sensitive information, or that future attempted cybersecurity attacks, incidents, or disruptions would not be successful or damaging. Cybersecurity attacks and risks in particular are becoming more varied, and include threats from diverse vectors such as social engineering/phishing, malware (including ransomware), malfeasance by insiders, human or technological error, as a result of malicious software or malicious code embedded in open-source software, misconfigurations, bugs or other vulnerabilities that are integrated into our (or our third party's) IT systems. The threat landscape is constantly evolving as threat actors become increasingly sophisticated in using techniques and tools – including artificial intelligence and other emerging technologies – for malicious purposes. We and certain of our third-party service providers have in the past experienced cyberattacks and other incidents, and we expect such incidents to continue in varying degrees. While to date no incidents have had a material impact on our operations, we cannot guarantee that material incidents will not occur in the future.

Any adverse impact on the availability, integrity or confidentiality of our IT systems or sensitive information, including any attempts to gain unauthorized access to information and systems and other security incidents or breaches, could lead to disruptions in critical systems, unauthorized release of information and corruption of data. They could also damage our reputation, lead to legal claims or proceedings, regulatory investigations and enforcement actions, significant costs from remedial actions, loss of business or potential liability. We cannot guarantee that any costs and liabilities incurred in relation to an attack or incident will be covered by our existing insurance policies or that applicable insurance will be available to us in the future on economically reasonable terms or at all.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer-based programs and those of third parties, including our well operations information, seismic data, electronic data processing and accounting data. If any of such systems or programs were to experience service interruptions, fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business. We may be involved in legal proceedings that could result in substantial liabilities.

Like many energy companies, in the ordinary course of our business, we are from time to time involved in various disputes and disagreements that may lead to legal and other proceedings, such as title, royalty or contractual disputes, regulatory compliance matters, land access disputes, appeals and judicial reviews of regulatory approvals, personal injury or property damage matters. Such legal proceedings are inherently uncertain, and their results cannot be predicted. Regardless of the outcome, such proceedings could have an adverse impact on us because of legal costs, diversion of management and other personnel and other factors. In addition, it is possible that a resolution of one or more such proceedings could result in liability, penalties or sanctions, as well as judgments, consent decrees or orders requiring a change in our business practices, which could materially and adversely affect our business, prospects, financial condition, results of operations, cash flows and ability to pay dividends on our common stock. Accruals for such liability, penalties or sanctions may be insufficient, and judgments and estimates to determine accruals or range of losses related to legal and other proceedings could materially change from one period to the next.

We are subject to risks related to corporate social responsibility, including the risk that our expectations or estimates regarding environmental, social and governance matters may not be achieved or may be incorrect.

Our business, as well as those of other companies, faces increasing public scrutiny related to ESG activities, which are increasingly considered to contribute to the long-term sustainability of a company's performance.

We risk damage to our brand and reputation if we fail, or are perceived to fail, to act responsibly in a number of areas, such as environmental stewardship and corporate governance and transparency. Adverse incidents with respect to ESG activities could impact the value of our brand, the cost of our operations and relationships with investors, all of which could adversely affect our business and results of operations. For example, we have been in the past, and may in the future be, subject to claims of "greenwashing" (e.g., if our carbon footprint is alleged to be greater than what we claim, or if our ESG claims (including our claims in relation to our goals in respect of operational net zero) turn out to be false or misleading). Our expectations and estimates regarding ESG matters, including the potential environmental impact of our development and initiatives, may not be achieved or may ultimately prove to be incorrect or out of keeping with evolving best practices, which may lead to additional claims or liability. The law in relation to false and misleading claims about ESG matters and statements about "net zero" emissions goals is evolving, and there continues to be risk that statements we have made could be deemed to be in breach of the Australian Consumer Law and other similar legislation in Australia or other jurisdictions. Breaches of these laws can result in significant financial penalties and other enforcement action.

Some of our ESG efforts may ultimately rely on the right to claim certain emissions offsets or other environmental attributes or to package such attributes with the natural gas we produce. This may be affected by evolving approaches to these matters, complex calculations or commercial agreements, and any disputes or ambiguities regarding such environmental attributes may negatively affect perceptions of our operations and products, subject us to litigation or stakeholder activism, require us to incur additional costs to procure replacement attributes, or otherwise adversely impact our operations.

We are also subject to evolving expectations on ESG matters from various stakeholders, including regulators, investors, customers, and business partners. See "*Increased attention to ESG matters and environmental conservation measures may adversely impact our business*."

Risks Related to Environmental, Legal Compliance and Regulatory Matters

We are subject to complex federal, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Exploration and production activities in the oil and natural gas industry within Australia are subject to extensive local, state, federal and international laws and regulations. We may be required to make material expenditures to comply with governmental laws and regulations, particularly in respect of the following matters:

- approvals for drilling operations and other regulated activities;
- land access;
- royalties and royalty increases;
- drilling and development bonds;
- cost recovery for regulatory approvals;
- securities and orphan well levies;
- reports concerning operations;
- the spacing of wells;
- unitization of oil accumulations;
- tenure, landholders, native title holders and traditional Aboriginal owners;
- greenhouse gas emission targets and offset requirements;
- water extraction and disposal;
- remediation or investigation activities for environmental purposes; and
- taxation.

Under these and other laws and regulations, we could be liable for personal injuries, property damage and other types of damages, penalties, and costs. Accordingly, non-compliance may impact our ability to commercialize or retain its assets, which may in turn impact its operational and financial performance. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations, loss of permits and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, or terminations or regulatory changes could have a material adverse effect on our financial condition and results of operations.

Our business is affected by government policy, which in turn may be influenced by international policies and laws. There is no guarantee that the current policy of the Australian Federal Government's for the investment and development of Australia's natural gas resources will not change in the future. In particular, there is a risk that the Australian Federal Government could shift its domestic or international policy. International policy developments have the potential to have an indirect impact on our operations, given that domestic policy makers might consider those developments in formulating and in setting the direction of local policy. For example, the International Energy Agency recently released a report in relation to its recommendations for a pathway to achieve global net zero emissions by 2050, and includes a key recommendation that no new oil and natural gas projects should be developed. It is unknown what impact the report might have, if any, on domestic policy development for natural gas. A shift in energy policy announced and adopted by the NT Government in relation to natural gas or the development of the Beetaloo would pose a similar risk. The NT Government had previously imposed a moratorium on the operations in the Beetaloo, which ended in 2018 following a scientific inquiry and certain recommendations.

Shifts in government policy could have varying degrees of impact on our operations and its profitability and could range from loss or reduction in industry incentives, preventing infrastructure development to moratoriums on future natural gas development in specific areas or across the Beetaloo.

We must comply with relevant laws and regulations in each jurisdiction in which we operate as it applies to the environment, tenure, land access, landholders, native title holders and traditional Aboriginal owners. Non-compliance with these laws and regulations and any special license conditions could result in suspension of operations, loss of permits or financial penalties. Non-compliance may impact our ability to commercialize or retain our assets, which may in turn impact our operational and financial performance.

Changes to these requirements (including, for example, new requirements relating to climate change, environmental protection and energy policy, and the government of the Northern Territory's commitment to implement the recommendations from the Final Report of The Scientific Inquiry into Hydraulic Fracturing) may restrict or affect our right or ability to conduct our activities.

Our exploration of the Beetaloo is dependent upon the maintenance (including renewal) of the relevant permits. Maintenance of the permits is dependent on, among other things, meeting the permit conditions imposed by the relevant authorities including compliance with work program and expenditure requirements. No assurance can be given that such title and access rights are not subject to unregistered, undetected or other claims or interests which could be materially adverse to our interests in the Beetaloo. Further titles or access rights may be disputed, which could result in costly litigation or disruption of the Company's operations.

Our exploration and production operations are subject to various types of federal, state, territorial and local laws and regulations, and may be restricted or subject to conditions in relation to certain environmental features (such as watercourses or sites of conservation significance). Applicable law regulates the location of wells; the method of drilling, well construction, well stimulation, hydraulic fracturing and casing design; water withdrawal and procurement from designated aquifers for well stimulation purposes; well production; spill prevention plans; the use, transportation, storage and disposal of water and other fluids and materials, including solid and hazardous wastes, incidental to natural gas and oil operations; surface usage and the reclamation of properties upon which wells or other facilities have been located; the plugging and abandoning of wells; the calculation, reporting and disbursement of royalties and taxes; and the gathering of production in certain circumstances.

Our production operations are subject to the discovery of commercially exploitable petroleum and the discretion of the Minister to grant a production license. Specifically, we will only be entitled to apply for a production license once a commercially exploitable petroleum discovery is made. Further, the Minister may grant the production license subject to such conditions as the Minister determines to be appropriate at any time, the Minister may direct the holder of a production license to maintain, increase or reduce the rate of recovery of petroleum from the area. The grant of any future production license to the Company over areas that are subject to native title rights and interests or are Aboriginal land will require engagement with the relevant native title holders and land councils in accordance with the Native Title Act and the ALRA as relevant. Any delays or costs in engaging with the relevant native title holders in negotiating new arrangements in respect of a production license may adversely impact the Company's ability to carry out petroleum extraction activities within the affected areas.

Our operations are also subject to the Petroleum Act, which allows for the unitization of a petroleum pool that extends beyond a license area, but which is desirable for efficiency and avoiding wasteful and harmful development and practices.

Environmental and occupational health and safety laws and regulations govern discharges of substances into the air, ground and water; the management and disposal of hazardous substances and wastes; the clean-up of contaminated sites; groundwater quality and availability; plant and wildlife protection; locations available for drilling; environmental impact studies and assessments required for permitting; restoration of drilling properties upon completion of drilling activities; and work practices related to employee health and safety.

To conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Complying with the laws, regulations and other legal requirements applicable to our business and any delays in obtaining related authorizations may affect the costs and timing of developing our natural gas resources. These requirements could also subject us to claims for personal injuries, property damage, penalties, costs and other damages. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could materially adversely affect our results of operations, cash flows and financial position. Our failure to comply with the laws, regulations and other legal requirements applicable to our business, even as a result of factors beyond our control, could result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties and damages as well as corrective action costs.

We face community opposition from certain parties with respect to our development of the Beetaloo and related operations, which could result in significant costs and delays and could impede our ability to obtain the government approvals required for such operations.

We have been the target of protests and adverse publicity from certain parties due to concerns with environmental issues or Indigenous rights, and there is a risk from existing or future community opposition to our operations. For example, two pastoralists whose pastoral leases are subject, in part, to our petroleum interests refused to enter into access agreements for us to conduct certain regulated activities which require an access agreement, and we were required to make applications to the relevant tribunal to obtain access agreements for such regulated activities.

Disapproval from local communities or other interested parties may lead to direct action that could impede our ability to carry out our operations, resulting in project delay, reputational damage and increased costs, and thus impact our financial performance. Such community opposition may include undertaking legal proceedings (including challenges to required governmental approvals), media campaigns and protests, which could result in significant legal costs and delays. If such community members were successful in their campaigns, we may not be able to obtain the permits and approvals we will need to carry out our commercial operations.

The exploration and development of natural gas in the Beetaloo can pose native title and heritage risks, potentially leading to legal disputes, operational disruptions, and reputational damage.

We are required to comply with the Native Title Act 1993 (Cth), and we operate on areas in which native title has been judicially determined to exist. Consultation and negotiations have occurred, leading to exploration agreements. Further agreements will be required for any production phase, but the exploration agreements anticipate production and provide the parameters for those negotiations and outcomes. We will also be required to comply with the ALRA for tenement applications over Aboriginal land (i.e., freehold land held by an Aboriginal Land Trust under the ALRA, or land subject to a deed of grant held in escrow by an Aboriginal Land Council under the ALRA). Compliance with either legislative regime and their respective requirements for negotiation and agreement can significantly delay the grant of exploration and production tenements, and substantial compensation may be payable as part of any agreement reached. Applications for exploration tenements over Aboriginal land can also be placed into moratorium for five years at a time under the ALRA (unless the Governor-General of Australia declares by proclamation that the Australian national interest requires that the license be granted). These legislative regimes may impact our existing or future activities, ability to develop projects and operational and financial performance.

In addition, we will also need to comply with the Northern Territory Aboriginal Sacred Sites Act 1989 (NT) ("SSA"), the Heritage Act 2011 (NT), the Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (Cth) and the ALRA in relation to sacred sites and certain Aboriginal cultural heritage. Sacred sites and Aboriginal cultural heritage have been identified within areas covered by the tenements in which we have an interest, and other such sites may exist. It is an offense under Part IV of the SSA to enter onto or remain on, carry out work on or use, or desecrate a sacred site without authority. All Sacred Sites are protected under the SSA, regardless of whether or not they are included on the register maintained under the SSA. Destruction, disturbance or harming protected sites and artifacts may result in us incurring significant civil and/or criminal penalties, which may adversely impact or delay our activities. In addition, in the event of damage to sacred sites and Aboriginal cultural heritage, remediation costs may be substantive. Compliance with these laws requires significant expenditure and non-compliance may potentially result in fines and requests for improvement action from the regulator all of which may result in limitations on actions and project delays or cost overruns.

Upon commencement of commercial production, we are required by the Australian government to produce natural gas in the Beetaloo on a Scope 1 net zero basis. We also have set an internal goal of producing natural gas with net zero equity Scope 1 and 2 emissions. Meeting these requirements and goals may increase our costs of production, and we may be unable to meet these requirements and goals.

Australian law requires that, upon commencement of commercial production and reaching the relevant threshold of 100,000 t-CO2-e emissions per financial year, we produce natural gas in the Beetaloo on a Scope 1 net zero basis. We also have set an internal goal of producing natural gas with net zero equity Scope 1 and 2 emissions. To achieve this, we intend to utilize renewables to supply our upstream operation power needs and integrate carbon capture and sequestration with our upstream production activities as well as purchase carbon credits as required, however there is no guarantee we will achieve such plans. If we are unable to utilize renewables to supply our upstream operation power needs and integrate carbon capture and sequestration with our upstream production activities to the extent we currently expect, if the price of carbon credits increases or if we have otherwise underestimated the amount of Scope 1 or Scope 2 emissions that we will need offset, then our costs of production will increase further which could have a material adverse effect on our results of operations.

We may not achieve, and there are potential risks associated with, our growth strategy and vision to become a operational net zero emissions producer. Achievement of our vision of becoming a operational net zero producer of gas is presently uncertain and depends on us being able to economically manage our carbon emissions, which could, for example, be impacted by availability of future revenues to fund various carbon initiatives, market pricing of carbon offsets, evolution in GHG accounting methodologies, technological developments affecting operations and costs of implementing sustainable practices. Failure, or perceived failure, to meet these or other goals or commitments regarding the ESG characteristics of our offerings may subject us to litigation or stakeholder activism (which may be costly) or otherwise adversely impact our business. For more information, see our risk factor titled "*We are subject to risks related to corporate social responsibility, including the risk that our expectations or estimates regarding environmental, social and governance matters may not be achieved or may be incorrect*."

Increased attention to ESG matters and environmental conservation measures may adversely impact our business.

Increasing investor and societal attention to climate change and ESG, rising expectations for companies to address climate change and develop voluntary ESG initiatives, and growing consumer demand for alternative forms of energy may result in increased costs (including but not limited to increased costs related to compliance, stakeholder engagement, contracting and insurance), reduced demand for our products, reduced profits, increased investigations and litigation and negative impacts on our access to capital markets. Increasing attention to climate change, environmental justice and environmental conservation, for example, may result in demand shifts for natural gas products and additional governmental investigations and private litigation against us. To the extent that societal, political, or other factors are involved, including factors associated with geopolitical considerations, it is possible that we could be subject to changing market conditions, liability, or loss of certain assets without regard to our ultimate role in the causation of or contribution to the asserted events or damages, or to other mitigating factors.

Opposition toward natural gas drilling and development activity has been growing globally. Companies in the natural gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental compliance and business practices. Anti-development activists are working to, among other things, reduce access to government lands and delay or cancel certain projects such as the development of natural gas shale plays or related fossil fuel infrastructure.

Our voluntary initiatives (such as voluntary disclosures, certifications, or goals, among others) to improve the ESG profile of our company and/or products or to respond to stakeholder expectations may be costly and may not have the desired effect. For example, we may ultimately be unable to complete certain initiatives or targets, either on the timelines initially announced or at all, due to technological or legal cost, or other constraints, which may be within or outside of our control. For example, we may undertake initiatives or disclosures based on estimates, assumptions, methodologies, or third-party information that is subsequently determined to be innacurate, unreasonable, or to not align with best practices. Our approaches to such matters may evolve as well, but we cannot guarantee that it will necessarily align with the expectations of any particular stakeholder.

If we fail to, or are perceived to fail to, comply with or advance certain ESG initiatives (including the timeline and manner in which we complete such initiatives), we may be subject to various adverse impacts, including reputational damage and potential stakeholder engagement and/or litigation, even if such initiatives are currently voluntary. For example, there have been increasing allegations of greenwashing against companies making significant ESG claims due to a variety of perceived deficiencies in disclosure, methodology, or performance, including as stakeholder perceptions of sustainability continue to evolve.

In addition, we expect there will likely be increasing levels of regulation, disclosure-related and otherwise, with respect to ESG matters. For example, various policymakers, such as the SEC and the Australian Treasury, have adopted, or are considering adopting, rules to require companies to provide significantly expanded climate- and sustainability-related disclosures, which may require us to incur significant additional costs to comply, including the implementation of significant additional internal controls, processes and procedures regarding matters that have not been subject to such controls in the past, and impose increased oversight obligations on our management and board of directors. Simultaneously, there are efforts by some stakeholders to reduce companies' efforts on certain ESG-related matters. Both advocates and opponents to certain ESG matters are increasingly resorting to a range of activism forms, including media campaigns and litigation, to advance their perspectives. To the extent we are subject to such activism, it may require us to incur costs or otherwise adversely impact our business. In addition, we note that standards and expectations regarding carbon accounting and the processes for measuring and counting GHG emissions and GHG emission reductions are evolving, and it is possible that our approach to measuring both our emissions and our approaches to reduce emissions may be, either currently or in the future, considered inconsistent with common or best practices with respect to measuring and accounting for such matters, reducing overall emissions and/or achieving "net zero" across any emissions scope. If our approaches to such matters fall out of step with common or best practice, we may be subject to additional scrutiny, criticism, regulatory and investor engagement or litigation, any of which may adversely impact our business, financial condition or results of operations. This and other stakeholder expectations will likely lead to increased compliance costs as well as scrutiny that could heighten all of the risks identified in this risk factor.

Organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with fossil fuel-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our access to and costs of capital. Also, institutional lenders may decide not to provide funding for fossil fuel energy companies based on climate change and natural capital related concerns, which could affect our access to capital for potential growth projects. Moreover, to the extent ESG matters negatively impact our reputation, we may not be able to compete as effectively to recruit or retain employees, customers, or business partners. Such ESG matters may also impact our suppliers, service providers, or customers, which may adversely impact our business, financial condition, or results of operations.

Federal and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of natural gas wells and adversely affect our production.

Public debate exists regarding the potential sub surface and surface impact of unconventional drilling, including concern about the impacts of unconventional drilling water. In addition, there are many regulatory requirements for us to adhere to including, but not limited to, those specified in the *Petroleum Act*, *Petroleum Regulations* (NT), *Petroleum (Environment) Regulations 2016* (NT), *Water Act* (NT), *Environment Protection Act 2019* (NT), *Environment Protection and Biodiversity Conservation Act 1999* (Cth) and the *Work Health and Safety (National Uniform Legislation) Act* (NT) and *Work Health and Safety (National Uniform Legislation) Regulations* (NT). Unconventional drilling requires large volumes of water (the availability and regulation of which may change over time) and there are costs associated with water disposal that may be required should we produce water in our wells. As more impacts of unconventional drilling are fully understood, it may be subject to additional regulations or restrictions from local, state, or federal governmental authorities, resulting in increased compliance costs. Any modification to the current requirements may adversely impact the value of our assets and future financial performance.

For example, on April 17, 2018, the NT Government announced that it accepted all 135 of the recommendations set out in the 'The Scientific Inquiry into Hydraulic Fracturing in the Northern Territory' (Fracking Inquiry Report). The implementation of the recommendations has resulted in a more rigorous regulatory regime by placing additional obligations on oil and natural gas companies including the introduction of a stricter code of practice for decommissioning onshore shale gas wells, requiring tenement holders to provide a non-refundable levy prior to granting any further production approvals and introducing no go zones where a person cannot explore or drill for petroleum resources. A number of the recommendations may affect the Company's tenements. In particular, some key recommendations include but are not limited to:
(a) decommissioning wells to implement a stricter code of practice setting out the minimum requirements for the decommissioning of onshore shale natural gas wells in respect of cement integrity tests, the repair of defects prior to abandonment, and cement plugs to be placed to isolate critical formations; (b) objections to allow for any person to object to the proposed grant of an EP; (c) compensation to landowners, a land access agreement must be negotiated and signed by the pastoral lessee and the natural gas company; (d) accountable industry practice to allow for the NT Government to develop and implement a financial assurance framework for the onshore shale natural gas industry prior to the grant of any further production approvals; (e) non-refundable levy for appropriate monitoring and remediation activities; (f) merits review to allow for a range of third parties to have standing to seek merits review in relation to decisions under the petroleum statue and regulations prior to the granting of production approvals; and (g) reserved blocks or no go zones, where certain areas must be declared reserved blocks (areas where a person cannot explore or drill for petroleum resources), each with an appropriate buffer zone.

Our operations are subject to risks relating to climate change that could increase compliance or operating costs, limit natural gas exploration and production areas, and reduce demand for the natural gas we produce.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been adopted, been considered for adoption, and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of carbon dioxide, methane and other GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs and regulations that directly limit GHG emissions from certain sources. As a natural gas development company, we are exposed to both transition risks and physical risks associated with climate change. Transitioning to a lower-carbon economy may entail extensive policy, legal, technology and market changes and, if demand for gas declines, we will find it difficult to commercialize any resources we discover.

The transition and physical risks associated with climate change (including also regulatory responses to such issues and associated costs) may significantly affect our operating and financial performance. For example, the Australian government announced its policy to target net zero carbon emissions economy-wide by 2050. In connection with that announcement, the Australian government designated that shale natural gas facilities in the Beetaloo that exceed the relevant threshold of 100,000 gross tons of CO2-e emissions per financial year will be given a “Zero” GHG baseline. Accordingly, once a natural gas producer has exceeded the 100,000 gross t-CO2-e Scope 1 threshold, the Company must demonstrate that it has achieved Scope 1 net zero emissions, either through operational measures (such as carbon capture and storage) or by purchasing carbon offsets. Various policymakers have also adopted, or are considering adopting, rules to require companies to provide significantly expanded climate-related disclosures. For more information, see our risk factor titled “*Increased attention to ESG matters and environmental conservation measures may adversely impact our business*.” In addition, the increased frequency or severity of natural disasters and weather events due to climate change could delay or prevent our ability to conduct our activities, which could negatively impact our financial performance.

Increasing attention to global climate change has resulted in increased risk of public and private litigation, which could increase our costs or otherwise adversely affect our business. A number of parties have sought to bring suit against oil and natural gas companies in state or federal court, alleging, among other things, that such companies contributed to climate impacts by producing, handling or marketing fossil fuels, or violate citizens’ rights by contributing to climate change, or alleging that companies have been aware of the adverse effects of climate change for some time but failed to adequately disclose those impacts. In some jurisdictions, litigation has also been brought to establish legal mandates for particular entities to take certain climate-related actions, such as pursuing aggressive emissions reductions for their Scope 3 emissions reductions, regardless of whether entities have established any such goals already. The ultimate outcome and impact to us of any such litigation cannot be predicted with certainty, and we could incur substantial legal costs associated with defending these and similar lawsuits in the future. Shareholder activism related to climate change has also recently been increasing in our industry, and shareholders may attempt to effect changes to our business or governance, whether by stockholder proposals, public campaigns, proxy solicitations or otherwise. Any of these risks could result in unexpected costs, negative sentiments about us, disruptions in our operations, increases to our operating expenses and reduced demand for our products, which in turn could have an adverse effect on our business, financial condition and results of operations.

There are also increasing financial risks for fossil fuel producers as various capital providers may elect in the future to shift some or all of their investments into non-fossil fuel energy related sectors. Many capital providers have also incorporated more substantial assessments of climate-related matters into their funding considerations, including how such funding may impact such capital providers’ own Scope 3 emissions, and may elect not to provide, or to continue not to provide, funding to fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero (“GFANZ”) announced that commitments from over 650 firms across over 50 countries had capital committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects.

Climate change could have an effect on the frequency or severity of weather events (including hurricanes, wildfires, droughts and floods), sea levels, the arability of farmland, changes in temperature and other meteorological patterns, and water availability and quality. If such effects were to occur, our development and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low lying areas, disruption of our production activities either because of climate related damages to our facilities or in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs (or decreased availability) for insurance coverage in the aftermath of such effects. Additionally, in response to changing climatic conditions, certain policymakers have proposed increased restrictions on the withdrawal and use of water for fossil fuel production or other industrial uses, which may either delay or prohibit our access to certain bodies of water; to the extent we do not have sufficient local water sources available, we may be required to incur substantial costs or curtail operations, which may become more significant in periods of drought or other water scarcity. Increasing water stress or other concerns about climate change may also increase policymakers or activists' scrutiny on any potential impacts of our operations on local water bodies regardless of any use we make thereof. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. Climate change may impact the cost or availability of insurance, and even where insurance is maintained we may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. Our various actions to mitigate our business risks associated with climate change require us to incur substantial costs and may not be successful, due to, among other things, the uncertainty associated with the longer-term projections associated with managing climate risks.

Our ability to pursue our business strategies may be adversely affected if we incur costs and liabilities due to a failure to comply with environmental, health and safety laws or regulations or a release into the environment.

Despite efforts to conduct activities in an environmentally responsible manner and in accordance with applicable laws, there is a risk that gas activities may cause harm to the environment which could impact production or delay future development timetables.

We are subject to laws and regulations to minimize the environmental impact of our operations and rehabilitation of any areas affected by our operations. Changes to environmental laws may result in the cessation or reduction of our activities, materially increase development or production costs or otherwise adversely impact our operations, financial performance or prospects. Penalties for failure to adhere to requirements and, in the event of environmental damage, remediation costs can be substantial and may not, in their entirety, be insurable. Compliance with these laws requires significant expenditure and non-compliance may potentially result in fines or requests for improvement action from the regulator.

In addition, if we were to be held responsible for environmental damage, in addition to remediation costs, we may suffer reputational damage, possible suspension or cessation of operations, revocation of permits or financial penalties.

We may incur significant costs and liabilities as a result of environmental, health and safety laws and regulations applicable to the operation of our wells, gathering systems and other facilities including, for example, the following laws, as amended from time to time.

- Petroleum Act 1984 (NT);
- Petroleum Regulations 2020 (NT);
- Petroleum (Environment) Regulations 2016 (NT);
- Water Act 1992 (NT);
- Environment Protection Act 2019 (NT);
- Environment Protection and Biodiversity Conservation Act 1999 (Cth);
- Northern Territory Aboriginal Sacred Sites Act 1989 (NT);

- Heritage Act 2011 (NT);
- Aboriginal and Torres Strait Islander Heritage Protection Act 1984 (Cth);
- Native Title Act 1993 (Cth);
- Aboriginal Land Rights (Northern Territory) Act 1976 (NT);
- The National Greenhouse and Energy Reporting Act 2007 (Cth); and
- Work Health and Safety (National Uniform Legislation) Act 2011 (NT).

These laws and their implementing regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water and disposals or other releases or threats of release to surface, soils and groundwater. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the incurrence of capital expenditures, the occurrence of delays in the permitting, development or expansion of projects and the issuance of orders enjoining some or all of our future operations in a particular area. Certain environmental laws impose strict joint and several liability, without regard to fault or legality of conduct, for costs required to clean up and restore sites where hazardous substances or other wastes have been disposed of or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, wastes or other materials into the environment. In addition, these laws and regulations may restrict the rate of natural gas production or underground injection, disposal, and sequestration of carbon dioxide. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations; however, there can be no assurance that such costs will not be material in the future or that such future compliance will not have a material adverse effect on our business and operating results.

In addition, as a result of these environmental, health and safety laws and regulations, and their impact on our operations, we rely on specialized contracted companies to perform the majority of the specialized services inherent in the oil and natural gas industry. As such, we rely on the ability of these contractors to provide trained labor and properly designed and maintained equipment unique to their services. With the cyclical nature of the oil and natural gas business, the personnel used by these specialized contractors to perform these services may differ significantly in experience levels. From time to time, these specialized contractors may use new personnel that are still in training or may further sub-contract these services to other companies or personnel. There is a risk that these sub-contractors are unqualified or under-trained or that their equipment is not properly designed or maintained, which could result in work being performed inadequately or unsafely.

Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or production or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Our future gathering systems and processing, treating and fractionation facilities will be subject to regulation by the Northern Territory that could have a material adverse effect on our operations and cash flows.

NT Government regulation of gathering systems and processing, treating and fractionation facilities includes safety and environmental requirements. In addition, several of our future gas gathering systems will be subject to non-discriminatory take requirements and complaint-based regulation with respect to our rates and terms and conditions of service. Northern Territory regulation may cause us to incur additional costs or limit our operations, any or all of which could have a material adverse effect on our operations and revenue.

We may face unanticipated water and other waste disposal costs as a result of increased water-related regulations.

We may be subject to regulation that restricts our ability to discharge water produced as part of our natural gas production operations. Productive zones frequently contain water that must be removed for the natural gas to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce natural gas in commercial quantities. The produced water must be transported from the leasehold and/or injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability. Where water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of applicable regulatory agencies, or we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies; water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water;
- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

Restrictions on drilling, completion, production or related activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Natural gas operations in our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife, such as those restrictions imposed under the *Environment Protection Act 2019* (NT) or *Environment Protection and Biodiversity Conservation Act 1999* (Cth) (the "EPBC Act"). Seasonal restrictions may limit our ability to operate in certain protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration, development and production activities that could have an adverse impact on our ability to develop and produce our reserves. To the extent species are listed or re-designated under the EPBC Act, or previously unprotected species are designated as threatened or endangered in areas where our properties are located, operations on those properties could incur increased costs arising from species protection measures and face delays or limitations with respect to production activities thereon. There is also increasing interest in nature-related matters beyond protected species, such as general biodiversity, which may similarly require us to incur costs or take other measures which may materially impact our business or operations.

Our business is subject to complex and evolving laws and regulations regarding privacy and data protection.

In connection with running our business, we handle information that relates to individuals and/or constitutes "personal information" or similar terms under applicable data privacy laws, including from and about business contacts, employees, investors, and website users. We are therefore subject to various federal, state, and foreign laws, regulations and other requirements relating to the privacy, security and handling of personal information. For example, certain laws and regulations laws impose transparency obligations, provide residents with rights in relation to their personal information, and restrictions on our disclosure of their information.

The regulatory environment surrounding data privacy and protection is constantly evolving and can be subject to significant change. New laws and regulations governing data privacy, data security or the processing of and the unauthorized disclosure of personal or confidential information pose increasingly complex compliance challenges, and could potentially elevate our costs and change our operations. Further, legislative activity and regulatory focus on data privacy and security, including in relation to cybersecurity incidents, have significantly increased in the United States and globally. Some such requirements restrict our ability to process personal information across our business and across country borders. Any failure to comply with these laws and regulations regarding data privacy, data security or the processing of personal information could result in significant penalties, and legal liability, and. We continue to monitor and assess the impact of these laws, which in addition to penalties and legal liability, could impose significant costs for investigations and compliance. Such event could materially harm our business, require us to change our business practices, and carry significant potential liability for our business should we fail or be alleged to fail to comply with any such applicable laws.

Risks Related to our Corporate Structure

We are a holding company. Our sole material asset is our equity interest in TR Ltd. and we will be accordingly dependent upon distributions from TR Ltd. to pay taxes and cover our corporate and other overhead expenses.

We are a holding company and have no material assets other than our equity interest in TR Ltd. See "*Business and Properties—General Development of Business and Corporate Reorganization*." We have no independent means of generating revenues. To the extent TR Ltd. has available cash, we intend to cause TR Ltd. to make distributions to us, in an amount at least sufficient to allow us to pay our taxes and reimburse us for our corporate and other overhead expenses. We may be limited, however, in our ability to cause TR Ltd. and its subsidiaries to make these and other distributions or payments to us due to certain limitations, including the cash requirements and financial condition of TR Ltd. and restrictions in any relevant debt instruments entered into by TR Ltd. or its subsidiaries and/other entities in which it directly or indirectly holds an equity interest. To the extent that we need funds and TR Ltd. or its subsidiaries are restricted from making such distributions or payments under applicable laws or regulations or under the terms of any future financing arrangements, or are otherwise unable to provide such funds, our liquidity and financial condition could be materially adversely affected.

We may be unable to achieve some or all of the benefits that we expect to achieve from the Corporate Reorganization, which could materially adversely affect our business, financial condition and results of operations.

We may not be able to achieve the full strategic and financial benefits expected to result from the Corporate Reorganization, or such benefits may be delayed or not occur at all. We may not achieve these and other anticipated benefits for a variety of reasons, including, among others, because we may experience unanticipated competitive developments, including changes in the conditions of industry and the markets in which we operate, including fluctuations in the prices of natural gas that could negate some or all of the expected benefits from the Corporate Reorganization.

If we do not realize some or all of the benefits expected to result from the Corporate Reorganization, or if such benefits are delayed, our business, expected future financial and operating results and our prospects could be adversely affected.

Risks Related to our Common Stock and our CDIs

The requirements of being a public company, including compliance with the reporting requirements of the ASX listing rules and the Exchange Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As our CDIs are publicly traded in Australia and our common stock is publicly traded in the United States, we need to comply with laws, regulations and requirements, certain corporate governance provisions of SOX, related regulations of the SEC and the requirements of the ASX and NYSE. Complying with these statutes, regulations and requirements occupies a significant amount of our time and causes us to incur significantly costs and expenses.

If, however, we do not follow those procedures and policies, or they are not sufficient to prevent non-compliance, we could be subject to liability, fines and lawsuits. These laws, regulations and standards are subject to varying interpretations and, as a result, their application in practice may evolve over time as new guidance is provided by regulatory and governing bodies. We intend to invest resources to comply with evolving laws, regulations and standards, and this investment may result in increased general and administrative expenses and a diversion of management's time and attention from revenue generating activities to compliance activities. If, notwithstanding our efforts to comply with new laws, regulations and standards, we fail to comply, regulatory authorities may initiate legal proceedings against us, and our business may be harmed.

Furthermore, Changes in foreign currency exchange rates could materially adversely affect our business, results of operations or financial condition.

In our operations, there are transactions and balances denominated in currencies other than the U.S. dollar (which is the currency used to report our results of operations and financial condition in our financial statements), consisting primarily of the Australian dollar. To the extent our assets and liabilities denominated in Australian dollars as of June 30, 2024 are not hedged, we estimate that a 5% change in the exchange rate versus the U.S. dollar would expose us to foreign currency gains or losses of $11.8 million.

In addition, all of our facilities are located in Australia, a majority of our officers and employees are residents in Australia and substantially all of our expenses are payable in Australian dollars. In the event that the U.S. dollar weakens compared with the Australian dollar, our results of operations or financial condition may be adversely affected, perhaps substantially.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders' best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies. Related party transactions can create the possibility of conflicts of interest with regard to our management. Such a conflict could cause an individual in our management to seek to advance his or her economic interests above ours. Further, the appearance of conflicts of interest created by related party transactions could impair the confidence of our investors. Our Audit & Risk Management Committee reviews related party transactions in accordance with our related party transaction policy; however, review of related party transactions by our Audit & Risk Management Committee does not mean such transactions will have the expected benefits and, as such, could have an adverse impact on our financial condition or results of operations.

Certain of our affiliates are participants in joint ventures or may have other rights with respect to properties in which we have interests. For instance, Daly Waters, which is controlled by Bryan Sheffield, is an equal owner of TB1 that owns our interests in EPs 76, 98 and 117. Certain actions, such as a sale of property or incurrence of indebtedness, will require the approval of Daly Waters or its representatives on the board of TB1. In addition, we have granted Daly Waters Royalty, which is controlled by Bryan Sheffield, and certain of our directors ORRIs in certain of the permits we have interests in. See "Business and Properties—Agreements Relating to the Development of our Assets" in this report and "Related Person Transactions" included in the 2024 Proxy Statement for further information.

Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our CDIs and common stock.

Our certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third-party to acquire us. In addition, some provisions of our certificate of incorporation and bylaws could make it more difficult for a third-party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- limitations on the removal of directors;
- our classified board of directors with directors serving staggered three-year terms;
- limitations on the ability of our stockholders to call special meetings;
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders;
- the requirement that the affirmative vote of the holders of at least 662/3% in voting power of all the then-outstanding shares of our stock be obtained to amend and restate our existing bylaws or to remove directors;
- the requirement that the affirmative vote of the holders of at least 662/3% in voting power of all the then-outstanding shares of our stock be obtained to amend our certificate of incorporation;
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal our bylaws; and
- establishing advance notice and certain information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

Our certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our certificate of incorporation provides that, to the fullest extent permitted by law, and unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware (or, in the event that the Chancery Court does not have jurisdiction, the Superior Court of the State of Delaware (Complex Commercial Litigation Division) or the federal district court for the District of Delaware) will be the sole and exclusive forum for any claims that (i) are based upon a violation of a duty by a current or former director or officer or stockholder in such capacity or (ii) as to which Title 8 of the Delaware Code confers jurisdiction upon the Court of Chancery, in each such case subject to such Court of Chancery having personal jurisdiction over the indispensable parties named as defendants therein. Section 22 of the Securities Act creates concurrent jurisdiction for federal and state courts over all suits brought to enforce any duty or liability created by the Securities Act or the rules and regulations thereunder. However, our certificate of incorporation provides that federal district courts of the United States of America will be the sole and exclusive forum for claims under the Securities Act. Section 27 of the Exchange Act creates exclusive federal jurisdiction over all suits brought to enforce any duty or liability created by the Exchange Act or the rules and regulations thereunder. As a result, the forum provision in our certificate of incorporation will not apply to suits brought to enforce any duty or liability created by the Exchange Act or any other claim for which the federal courts have exclusive jurisdiction. We will inform our investors in each report filed in accordance with the Exchange Act in which we describe the terms of our common stock that the forum provision in our certificate of incorporation will not apply to suits brought to enforce any duty or liability created by the Exchange Act or any other claim for which the federal courts have exclusive jurisdiction.

These provisions may have the effect of discouraging lawsuits against us or our directors, officers, employees or agents. Any person or entity purchasing or otherwise acquiring any interest in shares of capital stock of the Company will be deemed to have notice of and consented to the forum provisions in our certificate of incorporation. However, the enforceability of similar forum provisions in other companies' certificates of incorporation has been challenged in legal proceedings, and it is possible that a court could find these types of provisions to be unenforceable. In this regard, stockholders may not be deemed to have waived our compliance with the federal securities laws and the rules and regulations thereunder, including Section 22 of the Securities Act. If a court were to find these provisions of our certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

We do not expect to generate positive cash flow until at least 2026. As a result we do not expect to pay dividends on our CDIs or common stock in the foreseeable future. Consequently, the ability of CDI holders and common stockholders to achieve a return on investment will depend on appreciation in the trading price of our CDIs and common stock.

We do not anticipate generating positive cash from operations until 2026, at the earliest. Additionally, at such time we do generate positive cash flow, we anticipate that we will retain all of our future earnings for use in the operation of our business and for general corporate purposes. As a result, we do not expect to pay dividends on our CDIs or common stock in the foreseeable future. Any determination to pay dividends in the future will be at the sole discretion of our board of directors. Accordingly, investors must rely on sales of their CDIs or common stock after price appreciation, which may never occur, as the only way to realize any future gains on their investments.

We may issue preferred stock whose terms could adversely affect the voting power or value of our CDIs and common stock.

Our certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of our common stock.

We have identified a material weakness in our internal control over financial reporting. Any material weakness may cause us to fail to timely and accurately report our financial results or result in a material misstatement of our financial statements.

Subject to applicable reporting requirement exemptions we take advantage of as a newly reporting company and as an emerging growth company, we are required to comply with the SEC rules implementing Sections 302 and 404 of the SOX, which require management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of controls over financial reporting. Effective internal control over financial reporting is necessary for us to provide reliable and timely financial reports and, together with adequate disclosure controls and procedures, are designed to reasonably detect and prevent fraud. We are also required to report any material weaknesses in such internal control. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting such that there is a reasonable possibility that a material misstatement of our financial statements will not be prevented or detected on a timely basis.

In connection with the audit of our financial statements for fiscal years 2023 and 2024, we identified deficiencies in our internal control over financial reporting, which in the aggregate, constituted a material weakness. We determined that in both fiscal years, we had deficiencies relating to insufficiently designed and operating internal controls over financial reporting, including: i) lack of sufficient evidence retained of the performance of internal controls, ii) insufficient resources in key accounting and finance roles leading to inadequate segregation of duties, iii) lack of manage access and manage change IT general controls over the cloud-based enterprise resource planning system, and iv) accounting for complex transactions in accordance with US GAAP, which in the aggregate constitute a material weakness.

As part of our plan to address this material weakness, we are performing a full review, with the assistance of external consultants, of our processes and internal controls. We have implemented, and plan to continue to implement, new controls and processes. We will also provide training to control owners, supported by external consultants, as appropriate, in support of an effective internal control framework, including how to sufficiently document and evidence the operation of internal controls. We will also continue to hire accounting and finance personnel who possess the required technical knowledge to ensure reporting requirements are met and segregation of duties are maintained. Finally, we will implement a new enterprise resource planning system to better support our financial reporting, including any related internal controls. We cannot predict the success of our plan to remediate this material weakness or the outcome of our assessment of this plan at this time. If our steps are insufficient to successfully remediate the material weakness and otherwise establish and maintain an effective system of internal control over financial reporting, the reliability of our financial reporting, investor confidence in us, and the value of our common stock could be materially and adversely affected. We can give no assurance that this implementation will remediate this deficiency in internal control or that additional material weaknesses in our internal control over financial reporting will not be identified in the future. Our failure to implement and maintain effective internal control over financial reporting could result in errors in our financial statements that could result in a restatement of our financial statements, or cause us to fail to meet our periodic reporting obligations. For as long as we are an "emerging growth company" under the JOBS Act, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404.

Once we no longer qualify as an "emerging growth company," we will be required to have our independent registered public accounting firm provide an attestation report on the effectiveness of our internal control over financial reporting. An independent assessment of the effectiveness of our internal control over financial reporting could detect problems that our management's assessment might not. Undetected material weaknesses in our internal control over financial reporting could lead to financial statement restatements and require us to incur the expense of remediation. An adverse report may be issued if our independent registered public accounting firm is not satisfied with the level at which our controls are documented, designed or operating.

We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the SOX. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our CDIs and common stock.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, which apply to other public companies.

We are classified as an "emerging growth company" under the JOBS Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things, (i) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act, (ii) comply with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (iii) provide certain disclosure regarding executive compensation required of larger public companies or (iv) hold nonbinding advisory votes on executive compensation. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.235 billion of revenues in a fiscal year, have more than $700.0 million in market value of our common stock held by non-affiliates or issue more than $1.0 billion of non-convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

Because we have elected to take advantage of the extended transition period pursuant to Section 107 of the JOBS Act, our financial statements may not be comparable to those of other public companies.

Section 107 of the JOBS Act provides that an emerging growth company can use the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards. This permits an emerging growth company to delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. We are choosing to take advantage of this extended transition period and, as a result, we will comply with new or revised accounting standards on the relevant dates on which adoption of such standards is required for private companies. Accordingly, our financial statements may not be comparable to companies that comply with public company effective dates, and our stockholders and potential investors may have difficulty in analyzing our operating results by comparing us to such companies.

Investors who purchased shares of our common stock in the IPO may not be able to freely sell those shares in Australia during the 12 months after the issue date of those shares in the IPO and therefore will not be able to take advantage of any liquidity that may be available for CDIs traded on the ASX during that period, unless an exception applies or the Company is able to rely on applicable legislative relief and lodges a cleansing notice in accordance with regulatory requirements with the ASX.

The shares sold in the IPO may not be freely tradable in Australia during the 12 months after their issue date. In general, shares that were purchased in the offering may be resold in Australia during that period only to certain "sophisticated investors" and "professional investors" (as defined in the Australian Corporations Act) and certain persons associated with us under Section 708(12) of the Australian Corporations Act, and any subsequent resale of those shares will also be subject to the same restrictions during the 12 months after their issue date in the offering. So long as those restrictions are in effect, to the extent that investors who purchased shares in the offering are able to resell those shares in Australia, the price they receive may be different than the market price of our common stock. Likewise, while investors who purchased shares in the offering will be entitled to exchange those shares for CDIs, which are listed on the ASX, sales of those newly-issued CDIs in Australia will be subject to the same restrictions that are applicable to the underlying shares of common stock as described above. Investors who purchased shares in the IPO may not be able to freely sell those shares, or CDIs representing those shares, in Australia during the 12 months after the issue date of those shares in the offering. To the extent those newly issued CDIs are not freely tradeable, investors may not be able to take advantage of any liquidity which may be available for CDIs traded on the ASX during that period. Notwithstanding the foregoing, the Australian Securities and Investments Commission has granted Class Order Instrument 14/827 ("Class Order") which permits the issue and on sale of CDIs within the first 12 months of issue provided the Company has lodged a cleansing notice on ASX within applicable time limits after those such CDIs are issued. Accordingly, if the Company is able to rely on the Class Order and has lodged a cleansing notice in respect to those CDIs, those CDIs that have been issued on conversion of the Company's common stock (including common stock that is issued as a result of the IPO) may be freely tradable on ASX.

Our outstanding CDIs will be listed on the ASX and will be freely tradable in the public markets in Australia. Trading in our CDIs may have a material adverse effect on the trading price of our common stock on the NYSE.

Our common stock is traded on the NYSE and our CDIs are traded on ASX. The CDIs are, in general, the economic equivalent of shares of our common stock and, as a result, the trading price of the CDIs on the ASX will likely affect the trading price of our common stock on the NYSE, and vice versa. The trading price of the CDIs may be influenced by factors different from those that affect the trading price of our common stock on the NYSE and, as discussed below in these risk factors, may be influenced by arbitrage activities. In addition, holders of shares of our common stock may deliver those shares to the depositary for the CDIs in exchange for CDIs.

Trading in our securities on these markets takes place using different currencies (U.S. dollars on NYSE and Australian dollars on the ASX), and at different times (resulting from different time zones, trading days and public holidays in the United States and Australia). The trading prices of our securities on these two markets may differ due to these and other factors, including the fact that ASX and NYSE have different criteria for trading halts as well as different listing rules and disclosure requirements. Any decrease in the price of our CDIs on the ASX could cause a decrease in the trading price of our common stock on the NYSE.

The different characteristics of the capital markets in Australia and the United States may negatively affect the trading prices of our CDIs and common stock and may limit our ability to take certain actions typically performed by a U.S. company.

We are subject to ASX listing with respect to our CDIs, and associated Australian regulatory requirements, and concurrently list our shares on the NYSE as well, which has its own listing and regulatory requirements. Such exchanges have different trading hours, trading characteristics (including trading volume and liquidity), trading and listing rules, and investor bases (including different levels of retail and institutional participation). As a result of these differences, the trading prices of our CDIs and our common stock may not be the same, even allowing for currency differences. Fluctuations in the price of our common stock due to circumstances peculiar to the U.S. capital markets could materially and adversely affect the price of the CDIs, or vice versa. Certain events having significant negative impact specifically on the Australian capital markets may result in a decline in the trading price of our common stock notwithstanding that such event may not impact the trading prices of securities listed in the United States generally or to the same extent, or vice versa.

In addition, any shares of common stock received in exchange for CDIs will be considered restricted securities (as that term is defined in Rule 144 of the Securities Act) and will bear a legend restricting transfer. Holders must cause the restrictive legend to be removed from such shares of common stock in order for the shares to be freely transferable and eligible to trade on the NYSE. As a result, holders of CDIs may not initially be able to freely trade into U.S. public markets, which may result in trading price differences between our common stock on the NYSE and our CDIs on the ASX.

Our ability to raise additional capital may be significantly limited by listing rules of the ASX that limit the amount of common stock that we are permitted to issue without stockholder approval.

Limitations on new share issuances under ASX listing rules may significantly limit or prevent us from raising additional capital by issuing and selling shares of our common stock or other securities when such additional capital is required. In particular, the ASX listing rules will prohibit us from issuing, during any 12-month period, shares of our common stock in an amount greater than 15% of the total number of shares of our common stock then outstanding without the affirmative vote of the holders of a majority of the outstanding shares of our common stock. As discussed elsewhere in this report, we will require substantial additional financing to develop and commercialize our resources and execute our strategy and, because we do not have any revenues from natural gas sales and would likely be unable to raise capital by borrowing funds, we will be dependent primarily upon issuing and selling additional shares of common stock to obtain such financing. The foregoing listing rule of the ASX is substantially more restrictive than the comparable NYSE rule and, even with the approval of our shareholders to permit us to issue up to 25% of the total number of shares of our common stock then outstanding during the 12-month period commencing on the date we are admitted to the official list of the ASX, this rule may significantly limit or prevent us from raising funds by issuing and selling shares of our common stock, which may have a material adverse effect on our results of operations, financial condition and the development of our business. Moreover, seeking shareholder approval to issue common stock is likely to take considerable time and expense and there can be no assurance that any such approval will be given in the future.

An investor may have limited ability to bring an action against us or against our directors and officers, or to enforce a judgment against us or them, because we conduct a majority of our operations in Australia, and many of our directors and officers reside outside the United States.

We conduct substantially all of our operations in Australia. Many of our directors and officers and certain other persons named in this report are citizens and residents of countries other than the United States and a portion of the assets of the directors and officers and certain other persons named in this report and substantially all of our assets are located outside of the United States. As a result, it may not be possible or practicable for you to effect service of process within the United States upon such persons or to enforce against them or against us judgments obtained in U.S. courts predicated upon the civil liability provisions of the federal securities laws of the United States. Even if you are successful in bringing such an action, there is doubt as to whether Australian courts would enforce certain civil liabilities under U.S. securities laws in original actions or judgments of U.S. courts based upon these civil liability provisions. In addition, awards of punitive damages in actions brought in the United States or elsewhere may be unenforceable in Australia or elsewhere outside the United States. An award for monetary damages under U.S. securities laws would be considered punitive if it does not seek to compensate the claimant for loss or damage suffered and is intended to punish the defendant. The enforceability of any judgment in Australia will depend on the particular facts of the case as well as the laws and treaties in effect at the time. The United States and Australia do not currently have a treaty or statute providing for recognition and enforcement of the judgments of the other country (other than arbitration awards) in civil and commercial matters. As a result, our holders of our common stock may have more difficulty in protecting their interests through actions against us, our management or our directors than would shareholders of a corporation operating within the United States.

As a result of listing CDIs on the ASX, we are subject to the listing rules of the ASX, which may strain our resources, divert management's attention and affect our ability to manage our business or raise additional capital.

As a result of listing CDIs on the ASX, we are subject to the listing rules of the ASX, which may strain our resources, divert management's attention and affect our ability to manage our business or raise additional capital. The listing rules of the ASX differ from, and in some cases are more restrictive than, the rules and requirements of the NYSE, including restrictions that:

- limit non-executive director compensation to a maximum amount approved by shareholders at a general meeting;
- require that the terms of every class of our securities, including any preferred stock, be approved by the ASX;
- prohibit us from removing or changing the voting rights or dividend rights (if any) of our securities, except in certain circumstances;
- specify certain terms and conditions of options and rights plans;

- prohibit issuing equity securities without shareholder approval in the three months after we receive any notice in writing that a person proposes to make a takeover bid;
- limit the issuance of restricted (escrowed) securities; and
- prohibit "golden parachutes" or other termination benefits for officers upon a change in ownership or control of us.

These listing rules may, in some cases, limit our ability to take certain actions that would otherwise be permitted by NYSE rules and may affect our ability to manage our business and to attract and retain key management and scientific personnel. In addition, the listing rules of the ASX include approval and reporting requirements that differ from the requirements under the NYSE rules, such as requirements to:

- comply with required timetables for issuance of equity securities;
- deliver notice to the ASX prior to the release of restricted (escrowed) securities;
- file quarterly, half-yearly and annual periodic reports that include specific disclosure required by the listing rules of the ASX;
- obtain stockholder approval for certain related-party transactions and for securities issuances to directors;
- deliver drafts to the ASX of charter documents, debt and convertible securities documents, certain meeting notices and documents sent to certain holders of securities; and
- prior to release to any other person, release announcements through the ASX as the central collection point for market sensitive information.

Compliance with these additional rules will increase our legal and financial compliance costs, make some activities or transactions more difficult, time-consuming or costly, may limit or prevent us from raising additional capital by issuing and selling shares of our common stock or other securities and increase demand on our systems and resources. We applied to the ASX for, and received, certain waivers from the application of some of its listing rules; however, such waivers will not afford us relief from all of the increased restrictions and requirements imposed by such listing rules. Increases in our costs and expenses associated with compliance with the ASX listing rules will adversely impact our results of operations and financial condition. In addition, limitations on new share issuances under ASX listing rules may limit or prevent us from raising additional capital by issuing and selling shares of our common stock or other securities when such additional capital is required, which may have a material adverse effect on our results of operations, financial condition and the development of our business. See *"—Our ability to raise additional capital may be significantly limited by listing rules of the ASX that limit the amount of common stock that we are permitted to issue without stockholder approval*."

The market price of our common stock may be adversely affected by arbitrage activities.

Investors may seek to profit by exploiting the difference, if any, in the price of our shares of common stock as reflected by the trading price of our CDIs, which will represent shares of our common stock, on the ASX and the trading price of our shares of common stock on the NYSE. Such arbitrage activities could cause the price of our common stock or the CDIs representing our common stock, as the case may be, in the market with the higher value to decrease to the price set by the market with the lower value or could otherwise adversely affect the market price of our common stock. These arbitrage risks may be increased by the fact that our common stock is be quoted in U.S. dollars on the NYSE while our CDIs will be quoted in Australian dollars on the ASX, which may also give investors the opportunity to exploit the impact of fluctuations in currency exchange rates on the market price of our common stock and the CDIs.

Changes in accounting standards issued by the Financial Accounting Standards Board ("FASB") or other standard-setting bodies may adversely affect our financial statements.

Our financial statements are prepared in accordance with GAAP as defined in the Accounting Standards Codification ("ASC") of the FASB. From time to time, we are required to adopt new or revised accounting standards or guidance that are incorporated into the ASC. It is possible that future accounting standards we are required to adopt could change the current accounting treatment that we apply to our consolidated financial statements and that such changes could have a material adverse effect on our financial condition and results of operations.

In addition, the FASB is working on several projects with the International Accounting Standards Board, which could result in significant changes as GAAP converges with International Financial Reporting Standards ("IFRS"), including how our financial statements are presented. Furthermore, the SEC is considering whether and how to incorporate IFRS into the U.S. financial reporting system. The accounting changes being proposed by the FASB will be a complete change to how we account for and report significant areas of our business. The effective dates and transition methods are not known; however, issuers may be required to or may choose to adopt the new standards retrospectively. In this case, issuers would report results under the new accounting method as of the effective date, as well as for all periods presented. Any such changes to GAAP or conversion to IFRS would impose special demands on issuers in the areas of governance, employee training, internal controls and disclosure and would likely affect how we manage our business.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 1C. CYBERSECURITY

With the guidance of the Audit & Risk Management Committee, our Board is responsible for our risk management framework, including our strategy, policies, procedures and systems with respect to cybersecurity and information technology risks associated with us and our supply chain, suppliers and service providers. Our management team has developed and implemented a risk management program that includes cybersecurity risks as a risk category. Management has primary responsibility for supervising internal staff and external consultants assisting with cybersecurity matters, including those that assist management in staying informed about cybersecurity risks and incidents. Management updates the Committee on our cyber risk management program, and the Committee reports to the full Board regarding its activities, including those related to cybersecurity.

Key elements of our risk management program relating to cybersecurity include: implementing risk assessments designed to help identify material risks, including risks arising from cybersecurity threats to our critical systems and information; engaging external cybersecurity consultants to assess and assist with aspects of our security processes; and maintaining insurance coverage related to cybersecurity matters. Currently, our management team's experience includes over 50 years combined experience in leadership roles at public companies. We are investing in additional resourcing and cybersecurity measures as we grow.

We have not experienced any material risks from known cybersecurity threats, including as a result of any prior cybersecurity incidents, which have materially affected us, including our operations, business strategy, results of operations, or financial condition. However, there can be no assurance that our cybersecurity risk management program and processes, including controls, systems and processes that we have or will in the future implement, will be fully implemented, complied with or effective in protecting our systems and information. We face risks from cybersecurity threats that, if realized, are reasonably likely to materially affect us, including our operations, business strategy, results of operations, or financial condition. See our risk factor titled *"Our business could be negatively affected by security threats and disruptions, including electronic, cybersecurity or physical security threats, incidents and other disruptions."*

ITEM 3. LEGAL PROCEEDINGS

Other than given as below, as of the date of this report, we are not a party to any material pending legal proceedings, nor are we aware of any material civil proceeding or government authority contemplating any legal proceeding, and to our knowledge, no such proceedings by or against us have been threatened. We anticipate that we and our subsidiaries may from time to time in the future become subject to claims and legal proceedings arising in the ordinary course of business. It is not feasible to predict the outcome of any such proceedings, and we cannot assure that their ultimate disposition will not have a materially adverse effect on our business, financial condition, cash flows or results of operations.

On July 4, 2024, the Environment Centre Northern Territory (“ECNT”) lodged an Originating Application in the Northern Territory Civil and Administrative Appeals Tribunal (“NTCAT”) for a merits review of the Minister for Environment, Climate Change and Water Security’s (“Minister’s”) approval of TB1 Operator’s Shenandoah South Exploration & Appraisal Program EP98 and EP117 Environment Management Plan (“Shenandoah EMP”) (“NTCAT Merits Review”). On August 20, 2024 the TB1 Operator was added as a respondent to the NTCAT Merits Review. The NTCAT Merits Review commenced by ECNT under the Petroleum Act 1984 (NT) and the Petroleum (Environment) Regulations 2016 (NT). ECNT are seeking an order that the Minister’s Original Decision is set aside and substituted with a decision that the Tribunal Member is not satisfied the information provided in the Shenandoah EMP is sufficiently compliant with the Petroleum (Environment) Regulations 2016 (NT), including in relation to: (a) risks of wastewater spills and (b) risks in relation to inter-aquifer connectivity and an order that the Shenandoah EMP should be referred to the NT EPA for an independent assessment or, in the alternative, an order that varies the Minister’s original decision and establishes conditions in the Shenandoah EMP. There are no current applications commenced by the ECNT for a stay of the activities subject to the Shenandoah EMP and there is no current timetable whereby the ultimate hearing of the NTCAT Merits Review will be heard.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is currently listed on the New York Stock Exchange under the symbol "TBN."

As of September 1, 2024, there were 12 holders of record of our common stock.

We have not paid any cash dividends on our common stock to date. The payment of cash dividends in the future will be dependent upon our revenues and earnings, if any, capital requirements and general financial condition. The payment of any cash dividends will be subject to the discretion of our board of directors.

Information with respect to securities authorized for issuance under equity compensation plans is included herein under Item 12.

Except as previously disclosed on Current Reports on Form 8-K, there were no unregistered sales of equity securities for the year ended June 30, 2024.

On June 28, 2024, in connection with our IPO, we issued and sold 3,125,000 shares of our common stock at a price to the public of $24.00 per share, resulting in gross proceeds to us of $75 million and net proceeds to us of approximately $70.1 million, after deducting the underwriting discount. Offering expenses were approximately $6.2 million. All shares issued and sold were registered pursuant to a registration statement on Form S-1 (File No. 333-279119), as amended (the "Registration Statement"), declared effective by the SEC on June 26, 2024. BofA Securities, Inc., Citigroup Global Markets Inc., and RBC Capital Markets, LLC acted as representatives of the underwriters for the IPO. The IPO commenced June 26, 2024 and terminated on July 30, 2024 after sale of an additional 308,750 shares of common stock pursuant to a partial exercise of the underwriters' over-allotment option granted in connection with our IPO resulting in gross proceeds of $7.4 million and net proceeds to us of $7.0 million, after deducting the underwriting discount. We have used the net proceeds from the IPO to progress our initial development phase as described in "Use of Proceeds" of the Registration Statement.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") summarizes the significant factors affecting the operating results, financial condition, liquidity and capital resources, and cash flows of our Company for the years ended June 30, 2024 and 2023. This MD&A should be read in conjunction with, and is qualified in its entirety by, our consolidated financial statements, the accompanying notes to consolidated financial statements and other financial information included in this report. Except for historical information, the matters discussed in this MD&A contain various forward-looking statements that involve risks, uncertainties and assumptions and other important factors and are based upon judgments concerning various factors beyond our control. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of many factors, including those discussed under "Item 1A - Risk Factors" and elsewhere in this report, any of which could cause the Company's actual results, performance or achievements, or industry results, to differ materially from any future results, performance or achievements expressed or implied by such forward-looking statements. All forward-looking statements speak only as of the date on which they are made. We undertake no obligation to update such statements to reflect events that occur or circumstances that exist after the date on which they are made. Additionally, you should refer to the "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are an early stage, growth-driven independent natural gas exploration and production company focused on an integrated approach to the commercial development of the natural gas resources in the Beetaloo located within the Northern Territory of Australia. We and our working interest partners have EPs to approximately 4.7 million contiguous gross acres (1.9 million net acres to Tamboran) and are currently the largest acreage holder in the Beetaloo.

We are focused on developing early stage, unconventional gas resources within our portfolio. Our key assets are (i) a 25% non-operated working interest in EP 161, (ii) a 38.75% working interest in EPs 76, 98 and 117, where we are the operator, and (iii) a 100% working interest in EPs 136, 143 and EP(A) 197, where we are the operator, all of which are located in the Beetaloo.

Recent Developments

IPO Over-Allotment

In July 2024, the underwriters partially exercised their over-allotment option granted in connection with our IPO to purchase an additional 308,750 shares of common stock, resulting in gross proceeds of $7.4 million and net proceeds to us of $7.0 million, after deducting the underwriting discount.

Variation to EP 136 minimum requirements

The DITT granted a five-year extension for EP 136 for the period July 24, 2025, to July 23, 2030, with minimum work requirements of $23,283,260 including the drilling and multistage fracture stimulation of one horizontal well in Permit Year 2.

Progress on the NTLNG project

In July 2024, we executed an interim agreement with the NT Government for exclusive access to the Wirraway North land for our NTLNG project, subject to meeting certain milestones. This replaces the Do Not Deal letter agreement previously executed with the NT Government and will be the active agreement that secures the land for the Company until just before it considers a final investment decision on NTLNG. In August 2024, the Company appointed Bechtel to undertake pre-FEED engineering services for NTLNG for $4,620,000 until the end of March 2025. Pre-FEED activities are expected to be completed in 1H 2025.

Shenandoah South Pilot Project

In August 2024, we spudded the Shenandoah South well SS2H using the H&P FlexRig®.

Also in August 2024, the Company signed a contract with Liberty for the fracture stimulation of the six wells planned to be drilled from the Shenandoah South 2 well pad, being SS2H and SS3H, during 2024, plus the four wells planned for 2025.

Employee Awards

In August 2024, the Company granted 842,400 RSU awards under the 2024 Incentive Award Plan.

Rig 403 sale

In September 2024, we entered into an exclusivity agreement for the sale of Rig 403 for $8.5 million gross (excluding sales commission of 6%), which includes a $400,000 non-refundable payment for a 30-day exclusivity period.

Market Outlook

We believe natural gas can play a key role in supporting the emissions reduction targets of many regional markets through the transition of coal-to-gas fired power plants. To date the increasing global demand for LNG, as well as under-investment in new supply, is expected to lead to LNG supply shortages.

We have the potential, subject to achieving commercial viability in the Beetaloo, to supply natural gas to both Australian domestic and international LNG markets, which would support countries in the region in achieving their GHG emission reduction targets and help reduce global GHG emissions if LNG is adopted as an alternative to coal fired power. We are in the initial phase of development of our operations. Successful commercialization of the Beetaloo will require the development of the infrastructure necessary to conduct our business as planned on commercially acceptable terms. In addition, success of our business will rely on the Australian East Coast and the Asian LNG markets maintaining elevated prices relative to North America to offset the higher costs associated with developing infrastructure in the Beetaloo. The natural gas industry is cyclical and commodity prices are highly volatile. We expect the natural gas markets will continue to be volatile in the future. Our future revenue, profitability and future growth are highly dependent on the prices we will receive for natural gas production. See our risk factor titled "Natural gas prices are volatile. A reduction or sustained decline in prices may adversely affect our business, financial condition or results of operations and our ability to meet our financial commitments *or raise capital*."

Global, industry-wide supply chain disruptions have resulted in widespread shortages of labor, materials and services. Such shortages have resulted in our facing significant cost increases for labor, materials and services. Principally, commodity costs for steel and chemicals required for drilling, higher transportation and fuel costs and annual wage increases have increased our operating costs for fiscal years 2023 and 2024. Typically, as the price for natural gas increases, so do associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion to prices. Some supply chain constraints and inflationary pressures could persist into fiscal year 2025 but are expected to plateau, however we cannot accurately predict future supply chain constraints and inflation. We cannot predict the future inflation rate but to the extent inflation remains elevated, we may experience cost increases in our operations, including costs for drill rigs, workover rigs, hydraulic fracturing fleets, tubulars and other well equipment, as well as increased labor costs. If we are unable to recover higher costs through higher commodity prices, our future revenue stream, would be significantly impacted.

We are taking actions to mitigate supply chain and inflationary pressures. We are monitoring the situation and assessing its impact on our business, including with respect to our partners. For example, we pre-purchased long lead materials including casing and tubulars, chemicals and downhole equipment necessary for our planned development for fiscal year 2025. We have in place a 10-year option with H&P to contract for up to four additional FlexRigs®. We are working closely with other suppliers and contractors to ensure availability of supplies on site, especially fuel, steel and chemical supplies which are critical to many of our operations and are working on diversifying suppliers. However, these mitigation efforts may not succeed or be insufficient.

Factors that Affect Comparability of Future Results

Our financial condition and results of operations for the periods presented and future periods may not be comparable, either from period to period or going forward primarily for the following reasons:

Recent events and formation transactions

Tamboran was incorporated as a Delaware corporation on October 3, 2023 and does not have historical financial operating results prior to the Corporate Reorganization effective December 13, 2023. As a result of the Corporate Reorganization, Tamboran became the parent company of TR Ltd., and for financial reporting purposes, the financial statements of TR Ltd. became the financial statements of Tamboran. See "*Business and Properties—General Development of Business and Corporate Reorganization*."

Success in our development of our natural gas properties

Because we have no operating history in the production of natural gas, our future results of operations and financial condition will be directly affected by our ability to develop and commercialize our assets through our drilling programs and future sales and marketing.

Natural gas revenue

We have not generated any revenue from natural gas production since inception due to the current stage of our operations, which is exploration drilling of our assets to test their commercial viability. If and when we do commence natural gas production, we expect to generate revenue from such production. No revenue from natural gas production is reflected in our financial statements.

Operating costs and expenses

We have not yet commenced natural gas production. If and when we do commence production, we will incur additional operating costs and expenses, which may include lease operating expenses, workover costs, taxes and royalty fees. Our operating costs and expenses consisted of the following during fiscal years 2023 and 2024: salaries, share based compensation, and related taxes and benefits of personnel employed by us, professional fees for consultants, auditors, tax advisors and legal services, depreciation and amortization of natural gas properties, impairment of our natural gas properties, the loss on sale of assets due to the sale of rigs in fiscal year 2023, exploration expenses, and general and administrative expenses.

Acquisitions

We may continue to grow our operations and financial results through strategic acquisition opportunities that may arise relevant to our Beetaloo strategy. Additionally, we may from time to time effect divestitures of certain of our non-core assets.

Supply, demand, market risk and the impact on natural gas prices

As discussed above in "—*Market Outlook*," the natural gas industry historically has been cyclical with highly volatile commodity prices. Natural gas prices are subject to large fluctuations in response to relatively minor changes in the demand for natural gas. Prices are affected by current and expected supply and demand dynamics, including the market disruptions resulting from the Russian-Ukraine war, the impact of the COVID-19 pandemic and related erosion of demand for natural gas, supply growth driven by advances in drilling and completion technologies, resulting in increased supply in the global market. Other factors impacting supply and demand include weather conditions (including severe weather events), pipeline capacity constraints, inventory storage levels, basis differentials, export capacity, supply chain quality and availability, as well as other factors, the majority of which are outside of our control. These commodity prices are likely to remain volatile in the future. Sustained periods of low natural gas prices could materially and adversely affect our financial condition, our results of operations, the quantities of natural gas that we can economically produce and our ability to access capital. Since we have not generated revenues, these key factors will only affect us when we produce and sell natural gas.

U.S. reporting company expenses

Prior to our Corporate Reorganization, the ordinary shares of TR Ltd. were listed on the ASX. Following our IPO, and the listing of our common stock on the NYSE, we are subject to the periodic reporting requirements of the Exchange Act. Although we have been listed on the ASX and have been required to file financial information and make certain other filings with the ASX, our status as a U.S. reporting company under the Exchange Act will cause us to incur additional legal, accounting and other expenses that we have not previously incurred, including costs related to compliance with the requirements of the Sarbanes-Oxley Act. These incremental legal and financial compliance expenses are not included in our historical results of operations; therefore, our results of operations for future periods may not be comparable to our results of operations for the periods under review.

Results of Operations

Our functional currency is the Australian dollar, and our reporting currency is the U.S. dollar. For revenues and expenses reported in any period, we use the average currency exchange rate between U.S. dollars and Australian dollars for the period. For assets and liabilities, we use the current currency exchange rate as at the end of the period, based on the same source. Given the fluctuations in currency exchange rates, we may experience changes in reported amounts from period to period that occur primarily as a result of these fluctuations and that are not reflective of actual changes in our business or operations.

Currently, we are exposed to foreign exchange risk, particularly with the U.S. dollar and Australian dollar, as a result of revenue and expenses that are denominated in each currency. It is our policy to limit the use of financial derivatives and seek risk mitigation through natural hedges. These natural hedges include the maintenance of U.S. dollar and Australian bank accounts and deposits. Because our functional currency is the Australian dollar, our reported financial results are subject to fluctuation resulting from changes in the U.S. dollar to Australian dollar exchange rate.

The following tables present selected financial information for the periods presented (dollar amounts in thousands):

	Year ended June 30,	
	2024	**2023**
Revenue and other operating income	$ —	$ —
Operating costs and expenses:		
Compensation and benefits, including stock based compensation	(5,407)	(6,341)
Consultancy, legal and professional fees	(9,457)	(6,818)
Depreciation and amortization	(120)	(118)
Loss on sale of assets classified as held for sale	(26)	(12,585)
Accretion of asset retirement obligations	(892)	(601)
Exploration expense	(2,161)	(2,793)
General and administrative	(2,453)	(2,763)
Total operating costs and expenses	(20,516)	(32,020)
Other income:		
Interest income, net	691	31
Loss on extinguishment of debt	(3,884)	—
Fair value loss on convertible debt	(35)	—
Foreign exchange gain, net	36	130
Other expenses, net	(143)	(337)
Total other (expense)/income	(3,335)	(176)
Net loss	(23,851)	(32,196)
Foreign currency translation	(411)	1,633
Total comprehensive loss attributable to noncontrolling interest	(2,140)	108
Total comprehensive loss attributable to Tamboran	(22,121)	(30,671)

Fiscal Years Ended June 30, 2023 and June 30, 2024

Revenue and other operating income. We have not yet commenced natural gas production. Therefore, we did not realize any revenue and other operating income during fiscal years 2023 and 2024, respectively.

Compensation and benefits, including stock based compensation. Compensation and benefits, including stock based compensation, decreased by $0.9 million during fiscal year 2024, as compared to fiscal year 2023, due primarily to forfeiture of options during the period and, although the company increased headcount as compared to the prior period, the compensation of the majority of those employees has been capitalized to unproven properties.

Consultancy, legal and professional fees. Consultancy, legal and professional fees increased by $2.6 million during fiscal year 2024, as compared to fiscal year 2023, due to increased costs related to significant capital raising activities and related transactions including preparation for a U.S. initial public offering in addition to consulting costs related to government and community relations and midstream activities.

Loss on sale of assets classified as held for sale. Loss on sale of assets classified as held for sale decreased by $12.6 million during fiscal year 2024, as compared to fiscal year 2023, due to a write down of two rigs in the prior period which did not recur.

Accretion of asset retirement obligations expense. For fiscal year 2024, an expense for accretion of asset retirement obligations of $0.9 million was recognized. The recognition of such an expense was due to the accretion of asset retirement obligation liabilities in relation to all EPs, inclusive of EPs 76, 98, 117, 136 and 161, including for the two new wells drilled during the period.

Exploration expense. Exploration expense decreased by $0.6 million during fiscal year 2024, as compared to fiscal year 2023, due to the focus of the Company on drilling our SS1H and A3H wells. Our exploration expense consisted of costs related to topographical, geographical and geophysical studies and other indirect expenditure.

General and administrative. General and administrative costs decreased by $0.3 million during fiscal year 2024, as compared to fiscal year 2023 as a result of overhead allocations recovery from the joint venture. Our general and administrative expense consisted of the following during fiscal years 2023 and 2024: expenses related to travel, insurance, and office and administrative fees.

Interest Income, net. Interest income, net increased by $0.7 million during fiscal year 2024, as compared to fiscal year 2023, due to interest received from term deposits during the period.

Loss on extinguishment of debt. For fiscal year 2024, an expense for loss on extinguishment of debt of $3.9 million was recognized. The recognition of such an expense was due to the extinguishment of payables to H&P in exchange of the issuance of the 5.5% Convertible Senior Note due 2029 between Helmerich & Payne International Holdings, LLC, Tamboran Resources Corporation, and the guarantors thereto dated June 4, 2024 (the "Convertible Note" which was converted to common stock upon the IPO.

Foreign currency translation. In fiscal year 2024, we recognized a foreign currency translation loss of $0.4 million, primarily due to slight weakening of the Australian Dollar as of June 30, 2024, as compared to July 1, 2023. In fiscal year 2023, we recognized a foreign currency translation gain of $1.6 million, primarily due to the acquisition of assets from Origin amounting to A$81.9 million on November 9, 2023 and the strengthening of the Australian Dollar from that date to June 30, 2023. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at fiscal year-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized on our income statement.

Income Tax Expense. We have no income tax expense due to operating losses incurred for fiscal years 2023 and 2024. We have provided a full valuation allowance on our net deferred tax asset because management has determined that it is more likely than not that we will not earn income sufficient to realize the deferred tax assets during a foreseeable future period. Management will continue to assess the potential for realizing deferred tax assets based upon income forecast data and the feasibility of future tax planning strategies and may record adjustments to the valuation allowance against deferred tax assets in future periods, as appropriate, that could have a material impact on the statement of operations.

Liquidity and Capital Resources

We are a development stage enterprise and will continue to be so until commencement of substantial production from our natural gas properties. We do not expect to generate any revenue from production until 2026, at the earliest, which will depend upon successful drilling results, additional and timely capital funding, and access to suitable infrastructure. Until then our primary sources of liquidity are expected to be cash on hand, net proceeds from our IPO, and funds from future private and public equity placements, debt funding and asset sales.

We expect to incur substantial expenses and generate significant operating losses as we continue to develop our natural gas prospects and as we:

- complete our current appraisal drilling and testing program;
- develop and commercialize our assets, including development of pipelines, the proposed NTLNG facility and other infrastructure;
- opportunistically invest in additional natural gas assets adjacent to our current positions; and
- incur expenses related to operating as a public company and compliance with regulatory requirements.

Our future financial condition and liquidity will be impacted by, among other factors, the success of our exploration and appraisal drilling program, the number of commercially viable natural gas discoveries made, the quantities of natural gas discovered, the speed with which we can bring such discoveries to production, and the actual cost of exploration, appraisal and development of our prospects.

For the fiscal year ended June 30, 2025, we estimate that we will need to invest approximately $68 million to progress our development plans. We expect the additional proceeds of the IPO received in July 2024, together with our existing cash on hand, to be sufficient to fund our planned drilling and flow testing of SS2H and SS3H. However, we may require significant additional funds earlier than we currently expect in order to execute our strategy as planned. We may seek additional funding through asset sales or public or private financings. Additional funding may not be available to us on acceptable terms or at all. In addition, the terms of any financing may adversely affect the holdings or the rights of our stockholders. For example, if we raise additional funds by issuing additional equity securities, further dilution to our existing stockholders will result. If we are unable to obtain funding on a timely basis, we may be required to significantly curtail one or more of our planned activities. We also could be required to seek funds through arrangements with collaborators or others that may require us to relinquish rights to some of our assets which we would otherwise develop on our own, or with a majority working interest.

Cash and Cash Equivalents

The following table summarizes our key measures of liquidity for the periods indicated (in thousands).

	June 30, 2024	June 30, 2023
Balance Sheet Statistics:		
Cash & cash equivalents	$74,746	$6,426

As of June 30, 2024, we had $74.7 million of cash and cash equivalents. This balance represents an increase of $68.3 million from June 30, 2023, due to capital raises during the period of $134.6 million, net of fees, offset primarily by spending on operations, particularly drilling two appraisal wells in the fiscal period.

H&P Convertible Note Conversion

In June 2024, in connection with the IPO, 489,088 shares of common stock were issued to H&P pursuant to the terms of the Convertible Note that was issued in exchange and satisfaction of mobilization and related expenses incurred by us for the transportation of a H&P FlexRig® from the United States to the Northern Territory.

Capital Commitments

We had the following five-year capital commitments as of June 30, 2024 and June 30, 2023 which are not recognized as liabilities or payable in the consolidated statement of financial position (in thousands):

	June 30, 2024	June 30, 2023
Capital commitments:		
Sweetpea Petroleum Pty Ltd (“Sweetpea”)	$23,283	$42,465
EP 161	2,650	2,652
Beetaloo Joint Venture	62,642	54,209
Midstream	1,971	—

Sweetpea Commitments

As of June 30, 2024, Sweetpea committed to spend $23.3 million related to two licenses, EP 136 with total commitments of $14.1 million and EP 143 with total commitments of $9.2 million over the following five years.

In relation to EP 136, the Year 1 minimum work requirement is $0.2 million to undertake planning, design, contracting, and operational readiness by July 2026. The minimum expenditure for Permit Years 2-5 inclusive (July 2026 to July 2030) is $13.9 million, including drilling and multistage fracture stimulation of one horizontal well in Year 2, followed by evaluation of the results and development of viability assessments in the subsequent years.

In relation to EP 143, the Year 2 minimum work requirements, which include various desktop evaluations including subsurface studies, acquire, process and interpret 125km of 2D seismic survey and finalize land access negotiations with pastoralist for regulated activities for a minimum expenditure of $1.7 million by April 2025. The remaining committed spend for EP 143 of $7.5 million relates to Year 3 to Year 5 inclusive with minimum work requirements over the period May 2025 to April 2028.

EP 161

For the McArthur working interest in EP 161, we are obligated to contribute our share of expenses to uphold our stake in EP 161. Our commitment through March 2026 is $2.6 million based on the minimum work requirements. There are no minimum commitment requirements after March 2026.

Beetaloo Joint Venture

The terms of the Beetaloo Joint Venture necessitate specific work obligations through May 2028. These commitments include an expected spend of $62.6 million related to drilling and multi-stage hydraulic fracturing of six wells, a 2D seismic survey in each license and subsurface studies, with expenditure across EP 76 of $21.3 million, EP 98 of $20.0 million and EP 117 of $21.3 million.

Midstream

Tamboran and Daly Waters are in the process of forming a new joint venture which will own the SPCF, each with a 50% interest. Procurement of the long lead items for the compressor package and dehydration package was placed in June 2024 with progress payments for these items and other costs of $3.5 million required prior to the end of calendar year 2025.

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	Year Ended June 30,	
	2024	2023
Statement of Cash Flows:		
Net cash used in operating activities	$ (11,398)	$ (12,804)
Net cash used in investing activities	(66,109)	(107,465)
Net cash from financing activities	146,385	106,183

Net Cash Used in Operating Activities

For fiscal year 2024, net cash used in operating activities was $11.4 million during which we incurred a net loss of $23.9 million, compared to net cash used in operating activities for fiscal year 2023 of $12.8 million, during which we incurred a net loss of $32.2 million. The net loss for fiscal year 2024 included the non-cash impacts of depreciation and amortization, stock-based compensation, accretion of asset retirement obligations, loss on extinguishment of debt, and foreign exchange differences. Additionally, in the year ended June 30, 2024, net favorable changes in operating assets and liabilities totaled $6.9 million, primarily consisting of a $9.3 million increase in accounts payable and accrued expenses due to timing of our pay cycle during the fiscal period, a $0.1 million decrease in trade and other receivables, and a $2.4 million increase in prepaid expenses and other assets.

Net Cash Used in Investing Activities

For fiscal year 2024, net cash used in investing activities was $66.1 million compared to $107.5 million for fiscal year 2023. This change was primarily due to the acquisition of EPs 76, 98 and 117 in November 2022. In the current period there was spend on exploration and evaluation activities of $60.2 million in connection with the drilling, completion and stimulation of our initial appraisal wells, $2.9 million related to interest on financing lease liabilities, and the spend of $3.5 million related to SPCF offset by proceeds from the sale of property, plant and equipment of $0.4 million due to the sale of one rig.

Net Cash from Financing Activities

For fiscal year 2024, net cash received in financing activities was $146.4 million compared to $106.2 million received for fiscal year 2023. This change was primarily due to $148.6 million in proceeds from the issue of shares in connection with the Company's capital raises in fiscal year 2024, $17.2 million attributable to contributions from noncontrolling interest holders in connection with investments by Daly Waters, offset by transaction costs of $14.0 million, and repayments of finance lease liabilities of $5.5 million.

Critical Accounting Estimates

Management's discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our financial statements in conformity with GAAP requires us to make estimates and assumptions that affect the reported amounts of certain assets, liabilities and related disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The following critical accounting policies relate to the more significant estimates and assumptions used in preparing the consolidated financial statements.

Accounting for Natural Gas Properties

We are in the exploration stage and have not yet realized any revenues from our operations. We group our EPs into areas of interest according to geographical and geological attributes. We use the successful efforts method of accounting for expenditure incurred in each area of interest. Under this method, all general exploration and evaluation costs such as geological and geophysical costs are expensed as incurred. The direct costs of acquiring the rights to explore, drilling exploratory wells and evaluating the results of drilling are capitalized as exploration and evaluation assets (as a part of unproved properties) pending the determination of the success of the well. If a well does not result in a successful discovery, the previously capitalized costs are immediately expensed.

Impairment of Natural Gas Properties

Where an indicator of impairment exists for an unproved property and it is determined that future appraisal drilling or development activities are unlikely to occur, an impairment expense is recorded. Upon approval of the commercial development of a project, the exploration and evaluation asset is classified as a development asset. Once production commences, development assets are transferred to property, plant and equipment and are depleted using the unit-of-production method based upon estimates of proved developed reserves.

Joint Interest Activities

Some of the Company's exploration, development and production activities are conducted jointly with other entities whereby each party holds an undivided interest in each asset and is proportionately liable for each liability in the scope of such arrangement. The Company has recognized its proportionate share of assets, liabilities, revenues and expenses in respect of such arrangements. These have been incorporated in the consolidated financial statements under the appropriate classifications.

Asset Retirement Obligations

Our asset retirement obligations ("AROs") consist primarily of estimated future costs associated with the plugging, dismantling, removal, site reclamation and similar activities of natural gas properties in accordance with the requirements of respective EPs and with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the related long-lived asset. The recognition of an ARO requires numerous assumptions to be made by management regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized cost, including revisions thereto, is charged to expense through depreciation and amortization over the life of the related asset.

Litigation and Environmental Contingencies

In the ordinary course of business, we may at times be subject to claims and legal actions. Management does not believe the impact of such matters will have a material adverse effect on our financial position or results of operations. We are subject to extensive federal, state, and local environmental laws and regulations, which may materially affect our operations. These laws, which are constantly changing, regulate the discharge of materials into the environment and may require us to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites.

In our acquisition of existing assets, we may not be aware of what environmental safeguards were taken during the time such assets were operated or the environmental liabilities associated with such assets.

We maintain comprehensive insurance coverage that we believe is adequate to mitigate the risk of any adverse financial effects associated with these risks. However, should it be determined that a liability exists with respect to any environmental cleanup, remediation, or restoration, the liability to cure such a violation could still fall upon us. No claim has been made, nor are we aware of any liability which we may have, as it relates to any material environmental cleanup, remediation, restoration, or the material violation of any rules or regulations relating thereto.

Environmental expenditures are expensed or capitalized depending on their future economic benefit. Those related to an existing condition caused by past operations and that have no future economic benefits are expensed as incurred. Liabilities for expenditures of a noncapital nature are recorded when environmental assessment and/or remediation is probable, and the cost can be reasonably estimated.

Income Taxes

Income taxes are accounted for under the asset-and-liability method. Deferred tax assets and liabilities occur when differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards exist and are recognized for future tax consequences. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Current income tax recognized in the profit or loss is the tax payable or receivable on taxable income calculated using applicable income tax rates enacted as at reporting date. Current tax liabilities or assets are measured at the amounts expected to be paid or recovered from the relevant tax authority.

In assessing the probability that a deferred tax asset will be realized management considers whether it is more likely than not that all or some portion of the deferred tax assets will not be realized. We provide valuation allowances against deferred tax assets that are not considered more likely than not to be realized. The valuation of the deferred tax asset is dependent on, among other things, our ability to generate a sufficient level of future taxable income, in estimating future taxable income, we consider both positive and negative evidence in our assessment. If our estimate of future taxable income or tax strategies changes at any time in the future, we would record an adjustment to our valuation allowance. Recording such an adjustment could have a material effect on our financial condition or results of operations.

Deferred income tax relating to timing difference and unused tax losses are only recognized to the extent that it is probable that future tax profit will be available against which the benefits of the deferred tax asset can be utilized.

Stock-Based Compensation

We measure and recognize compensation expense related to our share-based compensation based on the estimated fair value of the awards. The fair value of the award is measured at the grant date and is recognized as an expense over the course of the award's vesting period. The fair value of the stock options granted is estimated using either the Black-Scholes (for awards that vest based on service conditions) or the Monte-Carlo option-pricing model (for awards that vest based on market conditions). Each of these models include the share price at grant date, exercise price, the term of the right, expected price volatility of the underlying share, the expected dividend yield and the risk-free interest rate for the term of the right. The Monte Carlo model also incorporates a probability-based value impact of the market condition.

Recent Accounting Pronouncements

See “Note 2—Summary of Significant Accounting Policies” to our consolidated financial statements included elsewhere in this report for more information about recent accounting pronouncements, the timing of their adoption, and our assessment, to the extent we have made one, of their potential impact on our financial condition and our results of operations.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not required.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The financial statements and supplementary information specified by this Item 8 are presented in Part IV, Item 15 “Exhibits and Financial Statement Schedules”.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

In connection with the audit of our financial statements for the fiscal years 2023 and 2024, we identified deficiencies in our internal control over financial reporting, which in the aggregate, constituted a material weakness. We determined that in both fiscal years, we had deficiencies relating to insufficiently designed and operating internal controls over financial reporting, including: i) lack of sufficient evidence retained of the performance of internal controls, ii) insufficient resources in key accounting and finance roles leading to inadequate segregation of duties, iii) lack of manage access and manage change IT general controls over the cloud-based enterprise resource planning system, and iv) accounting for complex transactions in accordance with US GAAP, which in the aggregate constitute a material weakness. Due to this material weakness, our principal executive officer and principal financial officer concluded that we did not maintain effective internal control over financial reporting for fiscal years 2023 and 2024.

As part of our plan to address this material weakness, we are performing a full review, with the assistance of external consultants, of our processes and internal controls. We have implemented, and plan to continue to implement, new controls and processes. We will also provide training to control owners, supported by external consultants, as appropriate, in support of an effective internal control framework, including how to sufficiently document and evidence the operation of internal controls. We will also continue to hire accounting and finance personnel who possess the required technical knowledge to ensure reporting requirements are met and segregation of duties are maintained. Finally, we will implement a new enterprise resource planning system to better support our financial reporting, including any related internal controls.

While we have begun implementing a plan to remediate this material weakness, we cannot predict the success of such plan or the outcome of our assessment of this plan at this time. If our steps are insufficient to successfully remediate the material weakness and otherwise establish and maintain an effective system of internal control over financial reporting, the reliability of our financial reporting, investor confidence in us, and the value of our common stock could be materially and adversely affected. We can give no assurance that this implementation will remediate this deficiency in internal control or that additional material weaknesses in our internal control over financial reporting will not be identified in the future. Our failure to implement and maintain effective internal control over financial reporting could result in errors in our financial statements that could result in a restatement of our financial statements, or cause us to fail to meet our periodic reporting obligations. For as long as we are an “emerging growth company” under the JOBS Act, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404.

Management's Annual Report on Internal Control over Financial Reporting

This report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the Company's independent registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Inherent Limitations on Effectiveness of Controls

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Because of its inherent limitations, internal control over financial reporting may not prevent or detect all control issues or misstatements. Accordingly, our controls and procedures are designed to provide reasonable, not absolute, assurance that the objectives of our control system are met. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become adequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in Internal Control Over Financial Reporting

There were no changes in the Company's internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) during the quarter ended June 30, 2024 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

During the three months ended June 30, 2024, no director or officer of the Company adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408 of Regulation S-K.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by Item 10 is incorporated herein by reference from our definitive proxy statement, which will be filed no later than 120 days after June 30, 2024.

Code of Business Conduct and Ethics

The Company's Code of Business Conduct and Ethics, which is applicable to all directors, officers and employees of the Company, including the principal executive officer, the principal financial officer and the principal accounting officer, is available on the Investor Relations section of the Company's website (www.tamboran.com). A copy is also available in print to share owners upon request, addressed to the Corporate Secretary at Tamboran Resources Corporation, Suite 01, Level 39, Tower One, International Towers Sydney, 100 Barangaroo Avenue, Barangaroo NSW 2000. The Company intends to post amendments to or waivers (to the extent applicable to the Company's directors, executive officers or principal financial officers) on its website.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is incorporated herein by reference from our definitive proxy statement, which will be filed no later than 120 days after June 30, 2024.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table summarizes securities authorized for issuance under equity compensation plans as of June 30, 2024.

	Equity Compensation Plan Information		
	(a)	(b)	(c)
Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)	Weighted-average exercise price of outstanding options, warrants and rights (2)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (3)
Equity compensation plans approved by security holders	272,506	$47.78	1,600,000
Equity compensation plans not approved by security holders	—	—	—
Total	272,506	$47.78	1,600,000

(1) Consists of the 2021 Equity Incentive Plan ("2021 EIP"). TR Ltd. adopted the 2021 EIP in connection with becoming a publicly listed company in Australia. As of June 30, 2024, options covering a total of 54,501,222 CDIs (representing 272,506 shares of our common stock) at a weighted average exercise price of A$0.362 remained outstanding under the 2021 EIP. There are no outstanding warrants.

(2) Consists of the 2021 EIP. Converted to U.S. Dollars at an exchange rate of 0.66. Holders of CDIs are the beneficial owner of one share of Common Stock for every 200 CDIs held.

(3) Following the IPO, no further grants have been or will be made under the 2021 EIP. This column reflects the total number of shares of common stock remaining available for issuance under the 2024 Incentive Award Plan as of June 30, 2024.

The additional information required by this Item 12, as well the names of all persons (of which the Company is aware) who are substantial holders in the Company within the meaning of section 671B of the Corporations Act, will be incorporated herein by reference from our definitive proxy statement, which will be filed no later than 120 days after June 30, 2024.

Australian Disclosure Requirements

In addition to the Company's primary NYSE listing, Common Stock are also quoted in the form of CDIs on the ASX and trade under the code "TBN". As part of our ASX listing, we are required to comply with certain of the disclosure and other obligations set out in the ASX Listing Rules. The following information is provided in accordance with the requirements of the ASX and the ASX Listing Rules (where that information has not been provided elsewhere in this report).

Place of Incorporation and Restrictions on the Acquisition of Securities

The Company is incorporated in the State of Delaware and is registered as a foreign company in Australia under the Corporations Act (ARBN 672 879 024). As a foreign company, the Company is not subject to Chapters 6, 6A, 6B or 6C of the Corporations Act (dealing with the acquisition of its shares, including substantial holdings and takeovers).

Under the Delaware General Corporation Law, shares in the Company are generally freely transferable. Transfers may, however, be subject to restrictions imposed by United States federal or state securities laws, by the Company's Certificate of Incorporation or Bylaws, or by an agreement signed with the holders of shares on issue.

The Company's Certificate of Incorporation and Bylaws do not impose any specific restrictions on the transfer of the Company's shares. Transfers of the Company's shares will be made only on the transfer books of the Company or by a transfer agent designated to transfer the Company's shares.

Repurchases of the Company's securities are governed by the safe harbor provisions set forth in Rule 10B-18 of the Securities Exchange Act of 1934. However, provisions of the Delaware General Corporation Law, the Company's Certificate of Incorporation and Bylaws could make it more difficult to acquire the Company by means of a tender offer (takeover), a proxy contest or otherwise, or to remove incumbent officers and directors of the Company. These provisions could discourage certain types of coercive takeover practices and takeover bids that the Company's Board may consider inadequate and encourage persons seeking to acquire control of the Company to first negotiate with the Board.

Issued Capital

As of September 12, 2024, the Company had 14,224,274 shares of Common Stock on issue, of which:

- 5,278,127 shares of Common Stock were held by 779 stockholders, and quoted on NYSE. (Note: The actual number of stockholders is greater than this number and includes holders who are beneficial owners, but whose shares are held in street name by brokers and other nominees. The number of active holders of record also do not include holders whose shares may be held in trust by other entities.); AND
- 8,946,147 shares of Common Stock were held by CHESS Depositary Nominees Pty Ltd (as Depositary Nominee) on behalf of 2,763 CDI holders, representing 1,789,229,400 CDIs quoted on ASX.

In addition, as of September 12, 2024, the Company had the following unquoted securities on issue which entitle the holder (upon vesting) to be issued Common Stock:

- 7,416,667 unquoted options exercisable at $0.2367 and expiring 26 May 2026, held by 3 option holders;

- 10,734,555 unquoted options exercisable at $0.32 and expiring 26 May 2026, held by 13 option holders;
- 842,400 Units, held by 40 employees of the Company pursuant to the Company's 2024 Incentive Award Plan;

Voting Rights

Each holder of Common Stock is entitled to one vote per Common Stock held. Holders of CDIs are entitled to receive notice of, and to attend as guests (but not vote at) meetings of stockholders. Holders of CDIs are the beneficial owner of one share of Common Stock for every 200 CDIs held. The Depositary Nominee (or its custodian) is the legal holder of the Common Stock underlying the CDIs.

As the beneficial owners, holders of CDIs may:

- direct the Depositary Nominee (or its custodian) how to vote the Common Stock represented by their CDIs by completing the CDI Voting Instruction Form that accompanies the relevant notice of meeting or proxy statement; or
- appoint themselves (or another person) to be the Depositary Nominee's proxy with respect to the Common Stock represented by their CDIs for the purposes of attending and voting at the meeting by completing the CDI Voting Instruction Form that accompanies the relevant notice of meeting or proxy statement.

Alternatively, holders of CDIs can elect to convert their CDIs into Common Stock and vote those Common Stock at the meeting. Such conversion must be completed prior to the record date fixed by the Company for determining the entitlement of stockholders to attend and vote at the meeting.

Options and Units do not carry voting rights.

Distribution of CDI Holders

Below is a distribution schedule of the number of holders of CDI's, at September 16, 2024.

	Number of Holders	Number of CDIs	%
1-1,000	42	5,849	0%
1,001-5,000	453	1,584,336	0.09%
5,001-10,000	381	2,998,470	0.17%
10,001-100,000	1,239	50,210,928	2.81%
100,001 and over	648	1,734,429,817	96.94%
	2,763	1,789,229,400	100.00%

Unmarketable parcels

The number of stockholders and/or CDI holders who hold less than a marketable parcel of securities (where a "marketable parcel" is a parcel of securities worth at least A$500, pursuant to the ASX Operating Rules) was 35, based on the closing price of the Company's common stock and CDIs as of September 12, 2024.

Twenty Largest CDI Holders

Below are details of the 20 largest holders of CDIs, and the number and percentage of issued CDIs held by those holders, as at September 12, 2024 and assuming all shares of Common Stock are held as CDIs.

	Name	**Number of CDIs Held[(1)]**	**Percentage of CDIs**
1 .	Sheffield Holdings LP	270,509,154	15.150%
2 .	HSBC Custody Nominees (Australia) Limited	258,456,660	14.475%
3 .	J P Morgan Nominees Australia Pty Limited	133,038,589	7.451%
4 .	Citicorp Nominees Pty Limited	121,375,210	6.798%
5 .	Helmerich & Payne International Holdings LLC	105,952,380	5.934%
6 .	Liberty Oilfield Services LLC	95,332,520	5.339%
7 .	HSBC Custody Nominees (Australia) Limited	74,287,520	4.161%
8 .	BNP Paribas Noms Pty Ltd	66,367,007	3.717%
9 .	David N Siegel	45,723,478	2.561%
10	Venture Holdings Sarl SPF	24,167,920	1.354%
11	Yeronda Nominees Pty Limited	22,970,912	1.287%
12	Jeffrey J Rooney <Siegel Dynasty A/C>	20,000,000	1.120%
13	BNP Paribas Nominees Pty Ltd <IB AU NOMS Retail client>	19,371,706	1.085%
14	HSBC Custody Nominees (Australia) Limited - A/C 2	17,985,125	1.007%
15	Jufran Carbon Pty Limited	16,592,461	0.929%
16	UBS Nominees Pty Ltd	16,370,172	0.917%
17	HSBC Custody Nominees (Australia) Limited <GSCO Customers A/C>	14,213,910	0.796%
18	Phillip Hollick Pty Ltd <Philly S/F A/C>	11,559,866	0.647%
19	BNP Paribas Nominees Pty Ltd <Hub24 Custodial Serv Ltd>	10,974,608	0.615%
20	John R Hislop	10,622,806	0.595%

(1) Including shares of Common Stock represented as though they were held as CDIs (with 200 CDIs representing a beneficial ownership interest in 1 share of Common Stock).

Additional Information

Rohan Vardaro is the Company’s corporate secretary.

Our principal executive office in Australia is Suite 01, Level 39, Tower One, International Towers Sydney 100 Barangaroo Avenue, Barangaroo NSW 2000 (telephone: +61 2 8330 6626). Our registered office in the United States is 1209 Orange Street, Wilmington, County of New Castle, Delaware 19801.

Registers of our securities are held as follows:

- For CDIs in Australia: Boardroom Pty Limited, Level 8, 210 George Street Sydney NSW 2000. Investor Enquiries: 1300 737 760 (within Australia) or +61 2 9290 9600 (outside Australia) between 8.30am and 5.30pm (Australian Eastern Standard time) Monday to Friday.
- For Common Stock in the United States: Computershare Trust Company, N.A., 250 Royall Street, Canton, MA 02021. Telephone: +1 781 575 3100.

There is no current on-market buy-back of the Company’s securities.

The Company does not have any restricted securities on issue, or securities subject to voluntary escrow.

No securities have been purchased on-market during the reporting period under or for the purposes of the Company's 2024 Equity Incentive Plan or to satisfy the entitlements of the holders of options or other rights to acquire securities granted under the 2024 Equity Incentive Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by Item 13 is incorporated herein by reference from our definitive proxy statement, which will be filed no later than 120 days after June 30, 2024.

Item 14. Principal Accountant Fees and Services

Our independent registered public accounting firm is Ernst & Young LLP (PCAOB ID No. 1435).

The information required by Item 14 is incorporated herein by reference from our definitive proxy statement, which will be filed no later than 120 days after June 30, 2024.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents filed as a part of this report.

(1) Financial Statements

See “Index to Consolidated Financial Statements” set forth on Page F-1.

(2) Financial Statement Schedules

Financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

EXHIBITS

(3) Exhibits

The following documents are filed as exhibits hereto:

Exhibit number	Description
3.1	Certificate of Incorporation of Tamboran Resources Corporation (filed as Exhibit 3.1 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Tamboran Resources Corporation (filed as Exhibit 3.2 to the Company's Registration Statement on Form S-1 dated June 17, 2024, File No. 333-279119, and incorporated herein by reference).
4.1	Form of Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1 dated June 17, 2024, File No. 333-279119, and incorporated herein by reference).
4.2	Scheme Booklet, dated as of October 27, 2023 (filed as Exhibit 4.2 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
4.3	Registration Rights Agreement, dated June 28, 2024, between Tamboran Resources Corporation, Sheffield Holdings, LP, and each of the other signatories from time to time party thereto (filed as Exhibit 10.1 to the Company's Form 8-K dated June 28, 2024, File No. 001-42149, and incorporated herein by reference).
4.4	Description of the Registrant's Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934 (filed herewith).
10.1	Form of Indemnification Agreement between the Company and each of the directors and officers thereof (filed as Exhibit 10.1 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.2†	Tamboran Resources Limited 2021 Equity Incentive Plan (filed as Exhibit 10.2 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.3†	Form of Tamboran Resources Limited 2021 Equity Incentive Plan Invitation Letter (filed as Exhibit 10.3 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.4†	Tamboran Resources Corporation 2024 Incentive Award Plan (filed as Exhibit 10.15 to the Company's Registration Statement on Form S-1 dated June 5, 2024, File No. 333-279119, and incorporated herein by reference).
10.5†	Form of Stock Option Agreement under the 2024 Incentive Award Plan (filed as Exhibit 10.16 to the Company's Registration Statement on Form S-1 dated June 5, 2024, File No. 333-279119, and incorporated herein by reference).
10.6†	Form of Restricted Stock Unit Grant Agreement under the 2024 Incentive Award Plan (filed as Exhibit 10.17 to the Company's Registration Statement on Form S-1 dated June 5, 2024, File No. 333-279119, and incorporated herein by reference).
10.7+	Joint Operating Agreement (Beetaloo Joint Venture) between Falcon Oil & Gas Australia Limited and Tamboran B2 Pty Ltd, dated July 28, 2023 (filed as Exhibit 10.5 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).

Exhibit number	Description
10.8	Royalty Deed (EP 76, EP 98, EP 117) – Daly Waters between Tamboran Resources Limited and Daly Waters Royalty, LP, dated September 18, 2022 (filed as Exhibit 10.6 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.9	Royalty Deed (EP 161) – Daly Waters between Tamboran Resources Limited and Daly Waters Royalty, LP, dated September 18, 2022 (filed as Exhibit 10.7 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.10	Royalty Deed (EP 136, EP 143 & EP 197) – Daly Waters between Sweetpea Petroleum Pty Ltd and Daly Waters LP, dated September 18, 2022 (filed as Exhibit 10.8 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.11#+	Onshore Drilling Contract between Sweetpea Petroleum Pty Ltd and Helmerich & Payne International Holdings, LLC dated September 9, 2022, as amended on June 7, 2023 (filed as Exhibit 10.9 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.12	Letter Agreement between Helmerich & Payne International Holdings, LLC and Tamboran Resources Limited, dated September 9, 2022 (filed as Exhibit 10.10 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.13†	Executive Employment Contract between Tamboran Resources Limited and Eric Dyer, dated May 5, 2021 (filed as Exhibit 10.11 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.14†	Executive Employment Contract between Tamboran Resources Limited and Joel Riddle, dated April 25, 2021 (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.15†	Employment Agreement between Tamboran Resources USA, LLC and Faron Thibodeaux, dated August 1, 2021 (filed as Exhibit 10.13 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.16†	Transfer of Employment with Tamboran Resources Limited and Offer of Employment by Tamboran Services Pty Ltd between Tamboran Resources Limited and Eric Dyer, dated February 13, 2023 (filed as Exhibit 10.14 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.17†	Transfer of Employment with Tamboran Resources Limited and Offer of Employment by Tamboran Services Pty Ltd between Tamboran Resources Limited and Joel Riddle, dated February 13, 2023 (filed as Exhibit 10.15 to the Company's Registration Statement on Form S-1 dated May 3, 2024, File No. 333-279119, and incorporated herein by reference).
10.18	Amended and Restated Joint Venture and Shareholders Agreement between Tamboran (West) Pty Limited, Tamboran Resources Limited, Daly Waters Energy, LP, Sheffield Holdings, LP and Tamboran (B1) Pty Ltd dated June 3, 2024 (filed as Exhibit 10.29 to the Company's Registration Statement on Form S-1 dated June 5, 2024, File No. 333-279119, and incorporated herein by reference).
10.19**	Director Nominating Agreement, dated June 28, 2024, between Tamboran Resources Corporation and Sheffield Holdings, LP (filed as Exhibit 10.2 to the Company's Form 8-K dated June 28, 2024, File No. 001-42149, and incorporated herein by reference).

Exhibit number	Description
21.1	Subsidiaries of the Company (filed as Exhibit 21.1 to the Company's Registration Statement on Form S-1 dated June 5, 2024, File No. 333-279119, and incorporated herein by reference).
23.1	Consent of Independent Registered Public Accounting Firm (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.1**	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350 (furnished herewith).
32.2**	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350 (furnished herewith).
97.1	The Company's Policy for Recovery of Erroneously Awarded Compensation (filed herewith).

** This exhibit shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

† Indicates a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report.

Portions of this exhibit (indicated by asterisks) have been omitted because the registrant has determined they are not material and would likely cause competitive harm to the registrant if publicly disclosed.

+ Certain schedules (or similar attachments) of this exhibit were omitted pursuant to Item 601(a)(5) of Regulation S-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Tamboran Resources Corporation

By: /s/ Joel Riddle
Name: Joel Riddle
Title: Chief Executive Officer

Date: September 20, 2024

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Joel Riddle Joel Riddle	Chief Executive Officer and Director (Principal Executive Officer)	September 20, 2024
/s/ Eric Dyer Eric Dyer	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	September 20, 2024
/s/ Richard Stoneburner Richard Stoneburner	Director	September 20, 2024
/s/ Fred Barrett Fred Barrett	Director	September 20, 2024
/s/ John Bell, Sr. John Bell, Sr.	Director	September 20, 2024
/s/ Patrick Elliott Patrick Elliott	Director	September 20, 2024
/s/ The Hon Andrew Robb AO The Hon Andrew Robb AO	Director	September 20, 2024
/s/ David Siegel David Siegel	Director	September 20, 2024
/s/ Stephanie Reed Stephanie Reed	Director	September 20, 2024
/s/ Ryan Dalton Ryan Dalton	Director	September 20, 2024

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Tamboran Resources Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Tamboran Resources Corporation and subsidiaries (the Company) as of June 30, 2024 and 2023, the related consolidated statements of operations and comprehensive loss, shareholders' equity and cash flows for each of the two years in the period ended June 30, 2024 and 2023, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company at June 30, 2024 and 2023, and the results of its operations and its cash flows for each of the two years in the period ending June 30, 2024 and 2024, in conformity with U.S. generally accepted accounting principles.

The Company's Ability to Continue as a Going Concern

The accompanying consolidated financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company has suffered recurring losses from operations and has stated that substantial doubt exists about the Company's ability to continue as a going concern. Management's evaluation of the events and conditions and management's plans regarding these matters are also described in Note 1. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young

We have served as the Company's auditor since 2019.

Sydney, Australia

September 20, 2024

TAMBORAN RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS
(In dollars)

	Note	June 30, 2024	June 30, 2023
ASSETS			
Current assets			
Cash and cash equivalents		$ 74,745,897	$ 6,426,306
Restricted cash		—	629,830
Trade and other receivables:			
Joint Interest Billing		10,298,322	—
ATO Receivable		700,115	821,979
Other Tax Receivables		11,514	7,774
Assets held for sale	4	8,366,000	8,818,509
Prepaid expenses and other current assets		3,209,033	317,634
Total current assets		97,330,881	17,022,032
Natural gas properties, successful efforts method:			
Unproved properties	4	230,119,448	163,385,971
Assets under construction - natural gas equipment	4	7,542,064	—
Property, plant and equipment, net	4	102,244	197,571
Operating lease right-of-use assets	5	962,052	459,113
Finance lease right-of-use assets	5	20,697,452	—
Prepaid expenses and other non-current assets		1,889,890	1,788,168
Total non-current assets		261,313,150	165,830,823
TOTAL ASSETS		$ 358,644,031	$ 182,852,855
LIABILITIES AND STOCKHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued expenses	6	$ 14,832,599	$ 14,471,663
Current portion of operating lease obligations	5	397,999	280,962
Current portion of finance lease obligation	5	12,767,400	—
Total current liabilities		27,997,998	14,752,625
Operating lease obligations	5	587,250	198,743
Finance lease obligation	5	14,141,713	—
Asset retirement obligations	7	8,140,992	7,182,739
Other non-current liabilities		90,378	137,802
Total non-current liabilities		22,960,333	7,519,284
Total liabilities		50,958,331	22,271,909
Commitments and contingencies (Note 13)			
Stockholders' equity			
Common stock, $0.001 par value; 10,000,000,000 and unlimited common stock authorized; 13,915,524 and 7,080,054 common stock issued and outstanding as at June 30, 2024 and 2023, respectively	9	13,915	7,080
Additional paid-in capital		404,594,023	259,298,821
Accumulated other comprehensive loss		(11,512,975)	(11,310,125)
Accumulated deficit		(130,379,771)	(108,461,300)
Total Tamboran Resources Corporation stockholders' equity		262,715,192	139,534,476
Noncontrolling interest		44,970,508	21,046,470
Total stockholders' equity		307,685,700	160,580,946
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY		$ 358,644,031	$ 182,852,855

See accompanying Notes to the Consolidated Financial Statements.

TAMBORAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS
(In dollars, except share amounts)

	Note	For the years ended June 30, 2024	2023
Revenue and other operating income		$ —	$ —
Operating costs and expenses			
Compensation and benefits, including stock-based compensation		(5,407,123)	(6,341,272)
Consultancy, legal and professional fees		(9,456,650)	(6,817,659)
Depreciation and amortization	4	(120,444)	(118,331)
Loss on sale of assets classified as held for sale	4	(25,605)	(12,584,768)
Accretion of asset retirement obligations	7	(891,961)	(600,959)
Exploration expense	16	(2,161,424)	(2,793,036)
General and administrative		(2,453,001)	(2,763,470)
Total operating costs and expenses		(20,516,208)	(32,019,495)
Loss from operations		(20,516,208)	(32,019,495)
Other income (expense)			
Interest income net		690,834	31,001
Loss on extinguishment of debt	8	(3,883,980)	—
Fair value loss on convertible debt		(34,700)	—
Foreign exchange gain, net		35,937	130,329
Other expense, net		(142,652)	(337,451)
Total other (expense) income		(3,334,561)	(176,121)
Net loss		(23,850,769)	(32,195,616)
Less: Net loss attributable to noncontrolling interest		(1,932,298)	(162,269)
Net loss attributable to Tamboran Resources Corporation stockholders		$(21,918,471)	$(32,033,347)
Comprehensive loss			
Net loss		$(23,850,769)	$(32,195,616)
Other comprehensive income (loss)			
Foreign currency translation		(410,815)	1,632,670
Total comprehensive loss		(24,261,584)	(30,562,946)
Less: Total comprehensive loss attributable to noncontrolling interest		(2,140,263)	107,614
Total comprehensive loss attributable to Tamboran Resources Corporation stockholders		$(22,121,321)	$(30,670,560)
Net loss per common stock			
Basic and diluted	12	$ (2.319)	$ (5.293)
Weighted average number of common stock outstanding			
Basic and diluted	12	9,450,244	6,052,044

See accompanying Notes to the Consolidated Financial Statements.

TAMBORAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In dollars)

	Common stock	Additional paid-in capital	Accumulated other comprehensive loss	Accumulated deficit	Total Tamboran Resources Corporation stockholders' equity	Non-controlling interest	Total stockholders' equity
Balance at July 1, 2022	$ 3,737	173,778,454	(12,672,912)	(76,427,953)	84,681,326	—	84,681,326
Issuance of common stock, net of issuance cost	3,343	84,611,462	—	—	84,614,805	—	84,614,805
Contributions from noncontrolling interest holders	—	—	—	—	—	20,938,856	20,938,856
Stock-based compensation	—	908,905	—	—	908,905	—	908,905
Foreign exchange translation	—	—	1,362,787	—	1,362,787	269,883	1,632,670
Net loss	—	—	—	(32,033,347)	(32,033,347)	(162,269)	(32,195,616)
Balance at June 30, 2023	7,080	259,298,821	(11,310,125)	(108,461,300)	139,534,476	21,046,470	160,580,946
Issuance of common stock, net of issuance cost	6,835	144,739,677	—	—	144,746,512	—	144,746,512
Contributions from noncontrolling interest holders	—	—	—	—	—	26,064,301	26,064,301
Stock-based compensation	—	555,525	—	—	555,525	—	555,525
Foreign exchange translation	—	—	(202,850)	—	(202,850)	(207,965)	(410,815)
Net loss	—	—	—	(21,918,471)	(21,918,471)	(1,932,298)	(23,850,769)
Balance at June 30, 2024	$13,915	$404,594,023	$(11,512,975)	$(130,379,771)	$262,715,192	$44,970,508	$307,685,700

See accompanying Notes to the Consolidated Financial Statements.

TAMBORAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In dollars)

	For the years ended June 30,	
	2024	**2023**
Cash flows from operating activities:		
Net loss	$ (23,850,769)	$ (32,195,616)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	120,444	118,331
Stock-based compensation	555,525	908,905
Foreign exchange gain, net	(35,937)	(130,329)
Loss on assets classified as held for sale	25,605	12,584,768
Accretion of asset retirement obligations	891,961	600,959
Non-cash interest on convertible notes	34,432	—
Loss on extinguishment of debt	3,883,980	—
Fair value loss on convertible debt	34,700	—
Changes in operating assets and liabilities:		
Trade and other receivables	118,124	(620,145)
Prepaid expenses and other assets	(2,430,729)	215,655
Accounts payable and accrued expenses	9,302,147	5,666,375
Other non-current liabilities	(47,424)	47,255
Net cash used in operating activities	(11,397,941)	(12,803,842)
Cash flows from investing activities:		
Payments for investments	—	(809,700)
Payments for property, plant and equipment	—	(12,835,149)
Payments for assets under construction	(3,516,014)	—
Payments for exploration and evaluation	(60,183,148)	(100,522,571)
Payment of interest on finance lease liabilities	(2,854,414)	—
Proceeds from sale of property, plant and equipment	444,568	2,463,100
Proceeds from government grants for exploration	—	4,239,622
Net cash used in investing activities	(66,109,008)	(107,464,698)
Cash flows from financing activities:		
Proceeds from issue of common stock	148,626,184	88,704,922
Contributions received from noncontrolling interest holders	17,206,459	20,938,856
Proceeds from issue of common stock, awaiting issuance	—	629,830
Common stock issue transaction costs	(13,976,892)	(4,090,117)
Repayment of lease liabilities	(5,470,379)	—
Net cash from financing activities	146,385,372	106,183,491
Net increase/(decrease) in cash and cash equivalents and restricted cash	68,878,423	(14,085,049)
Cash and cash equivalents and restricted cash at the beginning of period	7,056,136	18,469,563
Effects of exchange rate changes on cash and cash equivalents	(1,188,662)	2,671,622
Cash and cash equivalents and restricted cash at the end of period	$ 74,745,897	$ 7,056,136
Supplemental cash flow information:		
Non-cash investing and financing activities:		
Accrued capital expenditure	$ 2,797,103	$ 5,269,801
Accrued stock issuance costs	$ 1,640,892	$ —
Asset retirement obligations	$ (72,433)	$ (5,698,464)
Stock-based compensation	$ (555,525)	$ (908,905)
Contribution receivable from noncontrolling interest holders	$ 8,857,842	$ —
Operating lease right-of use assets and lease liabilities	$ (502,939)	$ 289,358
Interest accrued on finance lease liabilities	$ (277,966)	$ —
Finance lease right-of-use assets and lease liabilities	$ (32,104,131)	$ —
Non-cash finance lease costs capitalized to unproved properties	$ 14,539,059	$ —
Extinguishment of accrued capital expenditure	$ (7,785,000)	$ —
Convertible notes issued in exchange of extinguishment of debt	$ 11,668,980	$ —
Common stock for conversion of convertible notes	$ (11,738,112)	$ —

See accompanying Notes to the Consolidated Financial Statements.

TAMBORAN RESOURCES CORPORATION
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 – Nature of the Organization and Business

General

Tamboran Resources Corporation (the “Company” or “Tamboran” and together with its consolidated subsidiaries, the “Group”) is an early-stage growth-oriented natural gas company with a vision of supporting the net zero CO_2 energy transition in Australia and Asia-Pacific through developing low CO_2 unconventional gas resources in the Northern Territory of Australia. The Group is in the exploration stage with current focus on exploiting its primary assets, which are rights to working interests (“Tenements”) in exploration acreage in the Beetaloo sub-basin (“Beetaloo” or “Beetaloo Basin”), Northern Territory (“NT”), Australia. To date, the Group has not determined whether the Tenements contains any natural gas reserves that are economically recoverable. Further, the Group has no revenues from its gas operations as of June 30, 2024.

Reorganization

Tamboran acquired all of the issued and outstanding shares of Tamboran Resources Pty Ltd (f/k/a Tamboran Resources Limited) (“TR Ltd.” Or “predecessor”), our Australian predecessor and wholly owned subsidiary, pursuant to a Scheme of Arrangement (“Scheme”) under Australian law, which was approved by TR Ltd.’s shareholders on December 1, 2023, and the Federal Court of Australia on December 6, 2023. As part of the Scheme, the Group changed our place of domicile from Australia to the State of Delaware in the United States, effective on December 13, 2023.

In accordance with the Scheme, all ordinary shares of TR Ltd. were transferred to Tamboran, and Tamboran issued to the shareholders of TR Ltd., one CHESS Depositary Interest (“CDI”) for each ordinary share of TR Ltd., as held on the Scheme record date. Tamboran maintains an Australian Securities Exchange (“ASX”) listing for the Company’s CDIs, with each CDI representing 1/200th of a share of common stock. As a result of the reorganization, Tamboran became the parent company of TR Ltd., and for financial reporting purposes, the historical financial statements of TR Ltd. became Tamboran’s historical financial statements as a continuation of the predecessor. All share and per share data presented in the Group’s consolidated financial statements have been retroactively adjusted to reflect a one for two hundred (1:200) exchange ratio (“Exchange Ratio”) and all options over ordinary shares in the predecessor have been retroactively presented as options over CDIs in the Company.

Initial Public Offering (“IPO”)

On June 26, 2024, Tamboran’s Registration Statement on Form S-1, as amended, relating to the IPO was declared effective by the U.S. Securities and Exchange Commission (“SEC”) and the shares of its common stock began trading on the New York Stock Exchange (“NYSE”) on June 27, 2024. On June 28, 2024, the Company issued and sold 3,125,000 shares of common stock at a price to the public of $24.00 per share. The Company received net proceeds of approximately $67.2 million, after deducting expenses and underwriting discounts and commissions payable by the Company. The net proceeds of the IPO will be used for natural gas exploration and appraisal activities, progressing the Group’s three phases of development and other general corporate purposes.

The Company incurred $8.6 million of net offering costs in connection with the IPO which were recorded as an offset against IPO proceeds.

Following the IPO, holders of CDIs are able to trade their CDIs on the ASX and holders of shares of our common stock are able to trade their shares on NYSE under the symbol “TBN”. Holders of CDIs can elect to convert their CDIs on a 200 CDIs to one share of common stock of the Company should they want to trade their shares on NYSE.

Going concern and Management's liquidity plans

The accompanying consolidated financial statements have been prepared on the basis that the Group will continue as a going concern which contemplates the realization of assets and the satisfaction of liabilities in the ordinary and usual course of business.

As of June 30, 2024, the Group has:

- not generated revenues since inception, and is unlikely to generate earnings in the immediate or foreseeable future;
- a working capital surplus of $60,966,883 (excluding assets of disposal group held for sale) as a result of the IPO proceeds being received on June 28, 2024;
- an accumulated deficit of $130,379,771 since inception; and
- significant expenditures planned for the unproved properties and the Shenandoah South Pilot Project (Phase 1) in the next twelve months.

These factors raise substantial doubt regarding the Group's ability to continue as a going concern for the 12 months following the date these consolidated financial statements were available for issuance. The continuation of the Group as a going concern is dependent upon the ability of the Group to obtain necessary additional capital to fund ongoing exploration, appraisal and development projects and/or obtain oil and gas producing properties to attain future profitable operations. No assurance can be given that the Group will be successful in these efforts in the future.

Management has several plans in various stages of progress to source additional funding to provide operating capital for continued growth of the Group. Therefore, these consolidated financial statements do not include any adjustments related to the recoverability and classification of recorded asset amounts and classification of liabilities that might be necessary should the Group be unable to continue as a going concern.

Note 2 – Summary of Significant Accounting Policies

Basis of Preparation

The accompanying consolidated financial statements have been prepared in conformity with the accounting principles generally accepted in the United States of America ("U.S. GAAP") and rules and regulations of the SEC.

As a result of the reorganization, Tamboran became the parent company of TR Ltd., and for financial reporting purposes, the historical financial statements of TR Ltd. have become Tamboran's historical financial statements as a continuation of the predecessor.

Management's Use of Estimates

The preparation of the Group's consolidated financial statements in conformity with U.S. GAAP requires management to make judgements, estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as various disclosures in these consolidated financial statements. Management bases its judgements, estimates and assumptions on historical experience and on other various factors, including expectations of future events management believes to be reasonable under the circumstances. The most significant estimates included in, but not limited to, the preparation of these consolidated financial statements are related to asset retirement obligations, stock-based compensation, convertible notes and recoverability of oil and gas properties.

Although management believes these estimates are reasonable, these estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

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Principles of Consolidation

The consolidated financial statements include the accounts of the Company, all of its wholly owned subsidiaries and the variable interest entities ("VIE"), for which the Company or any of its subsidiaries is a primary beneficiary. All intercompany transactions, balances and unrealized gains on transactions between entities in the Group are eliminated upon consolidation. Unrealized losses are also eliminated unless the transaction provides evidence of the impairment of the asset transferred. Accounting policies of subsidiaries have been changed where necessary to ensure consistency with the policies adopted by the Group.

Under ASC 810, *Consolidation*, a reporting entity is the primary beneficiary if the reporting entity has both of the following characteristics: (a) the power to direct the activities of the VIE that most significantly affect the VIE's economic performance; and (b) the obligation to absorb losses, or the right to receive benefits, that could potentially be significant to the VIE.

Foreign Currency Translation

These consolidated financial statements are presented in US dollars ("$" or "dollars") and the functional currency of the Group is the Australian Dollar ("A$"). Adjustments resulting from the translation of functional currency financial statements to reporting currency are accumulated and reported as a part of "Accumulated Other Comprehensive Loss," a separate component of stockholders' equity.

Foreign currency transactions

Foreign currency transactions are translated into the Group's functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at financial year-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in the consolidated statements of operations and comprehensive loss.

Cash and Cash Equivalents

Cash represents cash deposits held at financial institutions. Cash equivalents include short-term highly liquid investments of sufficient credit quality that are readily convertible to known amounts of cash and have original maturities of three months or less. The Group had no restricted cash as of June 30, 2024. As of June 30, 2023, the Group had $629,830 in restricted cash related to cash received for shares, for which the shares had not yet been issued.

Trade and other receivables

As of June 30, 2024, and 2023, the Group's trade and other receivables are related to unpaid cash calls ("joint interest billing") owing from Daly Waters Energy ("DWE") which is a related party of the Group and goods and services tax receivable from the Australian Taxation Office. As of June 30, 2024, the Group had $10,298,322 receivable from joint interest billing. There were no receivables from joint interest billing as of June 30, 2023.

Trade and other receivable are recognized net of an allowance for doubtful accounts for expected credit losses, in the period when the Group's right to consideration is unconditional. The Group has no allowance for doubtful accounts related to its trade and other receivable for any reporting period presented.

Natural Gas Properties

The Group is in the exploration and appraisal stage and has not yet realized any revenues from its operations. The Group holds a number of exploration permits that are grouped into areas of interest according to geographical and geological attributes. Expenditure incurred in each area of interest is accounted for using the successful efforts method, as defined within ASC 932, *Extractive Activities – Oil and Gas*.

Under this method, all general exploration and evaluation costs such as geological and geophysical costs are expensed as incurred. The direct costs of acquiring the rights to explore, drilling exploratory wells and evaluating the results of drilling are capitalized as exploration and evaluation assets (as a part of unproved properties) pending the determination of the results of the well. If a well does not result in hydrocarbons being present, the previously capitalized costs are immediately expensed.

The carrying amounts of exploration and evaluation assets are reviewed at each reporting date to determine whether any indicators of impairment are present. Indicators of impairment include, but are not limited to:

- the right to explore has expired, or will expire in the near future, and is not expected to be renewed;
- further exploration for and evaluation of resources in the specific area is not budgeted or planned for;
- the Group has decided to discontinue activities in the area; or
- there is sufficient data to indicate the carrying value is unlikely to be recovered in full, from successful development or by sale based on changes brought by economic factors, commodity price outlook, favorable and/or unfavorable exploration activity on the property being evaluated and/or adjacent property.

Where an indicator of impairment exists for an unproved property and it is determined that future appraisal drilling or development activities are unlikely to occur, an impairment expense is recorded.

Upon approval of the commercial development of a project, the exploration and evaluation asset is classified as a development asset. Once production commences, development assets are transferred to property, plant and equipment and are depleted using the unit-of-production method based upon estimates of proved developed reserves.

Assets under construction include costs directly attributable to the construction or development of long-lived assets. These costs may include labor and employee benefits associated with the construction of the asset, site preparation, permitting, engineering, installation and assembly, procurement, insurance, legal, commissioning, and interest on borrowings to finance the construction of the assets. Depreciation is not recorded on the related assets until they are ready for their intended use. Repair and maintenance costs that do not extend the useful life of an asset are expensed as incurred.

Property, Plant and Equipment

Property, plant and equipment is stated at historical cost less accumulated depreciation and impairment, if any. Historical cost includes expenditure that is directly attributable to the acquisition of these items.

Depreciation is calculated on a straight-line basis over the expected useful lives of the asset as follows:

Leasehold improvements	Shorter of useful life (5 years) or unexpired period of lease term
Machinery work-in-progress	Not depreciated until machinery is fully operational

An item of property, plant and equipment is derecognized upon disposal or when there is no future economic benefit to the Group. Gains and losses between the carrying amount and the disposal proceeds are taken to profit or loss.

Leases

The Group accounts for leases under ASC 842, *Leases (“ASC 842”)*. The Group determines if an arrangement is a lease at inception of the arrangement and if such lease will be classified as an operating lease or a finance lease. The Group’s leases represent its right to use an underlying asset for the lease term. Right-of use (“ROU”) assets and liabilities are recognized at the lease commencement date based on the present value of lease payments over the lease term. As the Group's leases do not provide an implicit rate, the Group used a proxy for its incremental borrowing rate, which is the rate incurred to borrow on a collateralized basis over a similar term, an amount equal to the lease payments in a similar economic environment.

The Group has elected to account for lease and non-lease components in its contracts as a single lease component for all asset classes except for office premises.

Operating leases are included in "Operating lease right-of-use assets" within the Group's consolidated balance sheet. The Group's related obligation to make lease payments are included in "Current portion of operating lease obligations" and "Operating lease obligations" within the Group's consolidated balance sheet. Operating lease expense for lease payments is recognized on a straight-line basis over the lease term.

Finance leases are included in "Finance lease right-of-use assets" within the Group's consolidated balance sheet. The Group's related obligation to make lease payments are included in "Current portion of finance lease obligations" and "Finance lease obligations" within the Group's consolidated balance sheet. Finance lease expense includes amortization of the ROU assets and interest on lease liabilities. The Group capitalizes the finance lease expense as a part of unproved properties when the leased asset is directly involved in the drilling of wells (i.e., the finance lease expense is a direct cost of drilling wells).

Leases with a lease term of 12 months or less are not recorded on the balance sheet and are recognized as lease expense on a straight-line basis over the lease term. When it is reasonably certain the Group will exercise an option to extend the short-term lease beyond 12 months, the cost will be capitalized.

As a Lessor

Sublease income is recognized on straight-line basis over the term of the sublease agreement and is recorded within "Other expenses, net" in the consolidated statements of operations and comprehensive loss.

Impairment of Long-lived Assets

Impairment of long-lived assets is recorded when indicators of impairment are present and the undiscounted cash flows estimated to be generated by those assets are less than the assets' carrying value. The carrying value of the asset is then reduced to its estimated fair value which is usually measured based on an estimate of future discounted cash flows.

Joint Interest Activities

Some of the Group's exploration, development and production activities are conducted jointly with other entities whereby each party holds an undivided interest in each asset and is proportionately liable for each liability in the scope of such arrangement. The Group has recognized its proportionate share of assets, liabilities, revenues and expenses in respect of such arrangements. These have been incorporated in the consolidated financial statements under the appropriate classifications.

Asset Retirement Obligation

The Group's asset retirement obligation relates to the plugging, dismantling, removal, site reclamation and similar activities of its natural gas properties. The Group accrues the costs to dismantle and remove gas-related facilities upon exhaustion of reserves and related surface reclamation in accordance with ASC 410, *Asset Retirement and Environmental Obligations*. The Group recognizes the fair value of an asset retirement obligation as liabilities with an increase to the carrying amounts of the related long-lived assets in the period in which it is incurred if a reasonable estimate of fair value can be made. The asset retirement obligation is recorded as a liability at its estimated present value of expected future net cash flows and are discounted using the Group's credit adjusted risk-free rate. Over time, the liability is accreted to its present value, and the capitalized cost is depleted over the useful life of the related asset. Estimates are regularly reviewed by management and are revised for changes in future estimated costs and regulatory requirements. Revisions to estimated asset retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. Upon settlement of the liability, the Group either settles the obligation for its recorded amount or incurs a gain or loss.

Employee Benefits

Short-term employee benefits

Liabilities for wages and salaries, including non-monetary benefits expected to be settled wholly within 12 months of the reporting date, are measured at the amounts expected to be paid when the liabilities are settled.

Compensated absences

The Group provides annual leave and long service leave to its employees. These compensated absences are accounted for in accordance with ASC 710, *Compensated Absences*. The Group recognizes its liabilities for compensated absences depending on whether the obligation is attributable to employee services already rendered, rights to compensated absences vest or accumulate and payment is probable and estimable. The current and non-current compensated absences are included in “Accounts payable and accrued expenses” and “Other non-current liabilities,” respectively.

Defined contribution superannuation plan

Contributions to defined contribution superannuation plans for Australian employees and 401(K) plan for U.S. employees are expensed in the period in which they are incurred. The Group contributed $427,905 and $311,080 towards the superannuation plan during the years ended June 30, 2024 and 2023, respectively.

Stock-based Compensation

The Group applies the provisions of ASC 718, *Compensation – Stock Compensation* (“ASC 718”), which requires the measurement and recognition of compensation expense for all stock-based awards made to employees and non-employees, including employee stock options, in the consolidated statements of operations and comprehensive loss. Stock-based compensation awards granted to employees are measured using the grant date fair value of the awards and the resulting expense is recognized over the period during which the employees are required to perform service in exchange for the awards.

Stock-based compensation awards issued to non-employees for goods or services, are measured at either the grant date fair value of the goods or services received, or the instruments issued in exchange for such goods or services, whichever is more readily determinable.

The fair value of stock-based compensation awards that vest based on market conditions is measured using a Monte Carlo simulation model on the date of the grant. The fair value of stock options that vest based on service conditions is measured using the Black-Scholes option pricing model on the date of the grant. The Monte Carlo simulation model and the Black-Scholes option pricing model require the input of highly subjective assumptions, including, the term of the awards, the impact of dilution, the CDI price at grant date and expected price volatility of the underlying share, the expected dividend yield and the risk free interest rate for the term of the option, together with non-vesting conditions that do not determine whether the Group receives the services that entitle the employees or non-employees to receive payment.

Stock-based compensation expense is recognized on a straight-line basis over the vesting period for awards that are only subject to service conditions. The cumulative charge to consolidated statements of operations and comprehensive loss is calculated based on the grant date fair value of the award, the best estimate of the number of awards that are likely to vest and the expired portion of the vesting period.

The amount recognized in consolidated statements of operations and comprehensive loss for the period is the cumulative amount calculated at each reporting date less amounts already recognized in previous periods. Stock-based compensation expense is recognized using the accelerated attribution method for awards that are subject to market conditions.

Market conditions are taken into consideration in determining the fair value. Therefore, any awards subject to market conditions are considered to vest irrespective of whether or not that market condition has been met, provided all other conditions are satisfied. In certain circumstances where there are no future performance requirements by the employees and non-employees and the stock-based compensation awards are immediately vested, the total stock-based compensation expense is recorded in the period of the measurement date.

If there are any modifications or cancellations of the underlying unvested awards, the Group may be required to accelerate or increase any remaining unearned stock-based compensation expense.

Fair Value Measurements

ASC 820, *Fair Value Measurement* defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date; and assumes that the transaction will take place either: in the principal market; or in the absence of a principal market, in the most advantageous market.

Fair value is measured using the assumptions that market participants would use when pricing the asset or liability, assuming they act in their economic best interests. For non-financial assets, the fair value measurement is based on its highest and best use. Valuation techniques that are appropriate in the circumstances and for which sufficient data are available to measure fair value, are used, maximizing the use of relevant observable inputs and minimizing the use of unobservable inputs.

Assets and liabilities measured at fair value are classified into three levels, using a fair value hierarchy that reflects the significance of the inputs used in making the measurements as follows:

Level 1: Quoted (unadjusted) prices in active markets for identical assets or liabilities.

Level 2: Inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.

Level 3: Unobservable inputs for the asset or liability only used when there is little, if any, market activity for the asset or liability at the measurement date.

Classifications are reviewed at each reporting date and transfers between levels are determined based on a reassessment of the lowest level of input that is significant to the fair value measurement.

Fair value on a recurring basis

There were no material financial assets and liabilities accounted for at fair value on a recurring basis as of June 30, 2024 and 2023.

Fair value on a non-recurring basis

The Group applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including oil and gas properties and asset retirement obligations. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments if events or changes in certain circumstances indicate that adjustments may be necessary. Refer to Note 7 for fair value measurement of asset retirement obligations.

Items not recorded at fair value

The carrying amounts reported on the consolidated balance sheet for cash and cash equivalents, restricted cash, trade and other receivable, prepaid expenses, other assets, accounts payable, accrued expenses and other current liabilities approximate their fair values.

Fair Value Option

As permitted under ASC 825, *Financial Instruments* ("ASC 825"), the Group has elected the fair value option to account for its H&P Convertible Note ("Convertible Note"). In accordance with ASC 825, the Group recorded its convertible note at fair value.

The convertible note accounted for under the fair value option is a debt host financial instrument containing embedded features which would otherwise be required to be bifurcated from the debt-host and recognized as separate derivative liabilities subject to initial and subsequent periodic estimated fair value measurements under ASC 815, *Derivatives and Hedging* ("ASC 815"). Notwithstanding, ASC 825 provides the fair value option in respect of financial instruments, to the extent not otherwise prohibited by ASC 825, wherein bifurcation of an embedded derivative is not necessary, and the financial instrument is initially measured at its issue-date estimated fair value and then subsequently remeasured at estimated fair value on a recurring basis at each reporting period date.

The estimated fair value adjustment, as required by ASC 825, is recognized as a component of other comprehensive income with respect to the portion of the fair value adjustment attributed to a change in the instrument-specific credit risk (if any), with the remaining amount of the fair value adjustment recognized as other income (expense) in the accompanying consolidated statement of operations. With respect to the convertible note, as provided for by ASC 825, the estimated fair value adjustment is presented in a respective single line item within other income (expense) in the accompanying consolidated statements of operations and comprehensive loss, since the change in fair value of the convertible notes payable was not attributable to instrument specific credit risk.

Income Taxes

The Group accounts for income taxes under the asset and liability method in accordance with ASC 740, *Income Taxes*. The asset and liability method requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the financial reporting and tax bases of assets and liabilities and for operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using the currently enacted tax rates in effect for the years in which the differences are expected to reverse. Deferred tax is charged or credited in consolidated statements of operations and comprehensive loss, except when it is related to items credited or charged directly to equity, in which case the deferred tax is also dealt with in equity. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in consolidated statements of operations and comprehensive loss in the period that includes the enactment date.

Deferred tax assets are recognized to the extent that it is probable that taxable profit will be available against which deductible temporary differences can be utilized. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. An uncertain tax position is recognized as a benefit only if it is "more likely than not" that the tax position would be sustained in a tax examination on the basis of the technical merits of the position. The amount recognized is the largest amount of tax benefit that is more than 50% likely of being realized on examination. For tax positions not meeting the "more likely than not" test, no tax benefit is recorded.

As of June 30, 2024 and 2023, the Group did not have any amounts recorded pertaining to uncertain tax positions. The Group did not have any interest or penalties related to income taxes for the years ended on June 30, 2024 and 2023.

Net Earnings/(Loss) Per Share

Basic net earnings/ (loss) per share is calculated by dividing net earnings/ (loss) attributable to the owners of the Company by the weighted average number of common stock outstanding during the financial year, adjusted for bonus elements in common stock issued during the financial year.

Diluted earnings/ (loss) per share adjusts the figures used in the determination of basic earnings/ (loss) per share to take into account the after-income tax effect of interest and other financing costs associated with dilutive potential common stock and the weighted average number of additional common stock that would have been outstanding assuming conversion of all dilutive potential common stock.

Diluted loss per share is same as basic loss per share due to the lack of dilutive items in the Group for the financial years ended June 30, 2024 and 2023.

Concentration of Credit Risk

Credit risk represents the actual or perceived financial loss that the Group would record if its purchasers, operators, or counterparties failed to perform pursuant to contractual terms.

In the normal course of business, the Group maintains its cash in bank accounts with investment grade financial institutions. Management believes that the Group's counterparty risks are minimal based on the credit risk, reputation and history of the institutions selected.

The Group is not exposed to any significant credit risk.

Recent Accounting Pronouncements

In March 2024, the FASB issued ASU 2024-01, *Scope Application of Profits Interest and Similar Awards* ("ASU 2024-01"), which provides illustrative guidance to help entities determine whether profits interest and similar awards should be accounted for as share-based payment arrangements within the scope of ASC 718. The new standard is effective for annual periods beginning after December 15, 2024. The Group does not expect the adoption of this new guidance to have a material impact on the consolidated financial statements.

In December 2023, the FASB issued ASU 2023-09, *Improvements to Income Tax Disclosures* ("ASU 2023-09"), a final standard on improvements to income tax disclosures. The standard requires disaggregated information about a reporting entity's effective tax rate reconciliation as well as information on income taxes paid. The standard is intended to benefit investors by providing more detailed income tax disclosures that would be useful in making capital allocation decisions and applies to all entities subject to income taxes. The new standard is effective for annual periods beginning after December 15, 2024. The Group does not expect the adoption of this new guidance to have a material impact on the consolidated financial statements.

In November 2023, the FASB issued ASU 2023-07, *Segment Reporting: Improvements to Reportable Segment Disclosures* ("ASU 2023-07"). The amendments in the ASU require public business entities that disclose information on their reportable segments to provide additional information on their significant expense categories and "other segment items," which represent the difference between segment revenue less significant segment expense and a segment's measure of profit or loss. A description of "other segment items" is also required. Further, certain segment related disclosures that were limited to annual disclosure are now required at interim periods. Finally, public business entities are required to disclose the title and position of their Chief Operating Decision Maker ("CODM") and explain how the CODM uses the reported measures of profit or loss to assess segment performance. This guidance is effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. The Group does not expect the adoption of ASU 2023-07 to have a material impact on the consolidated financial statements.

In October 2023, the FASB issued ASU 2023-06, *Disclosure Improvements: Amendments—Codification Amendments in Response to the SEC's Disclosure Update and Simplification Initiative* ("ASU 2023-06"). The amendments in the ASU introduce changes to U.S. GAAP that originate in either SEC Regulation S-X or S-K, which are rules about the form and content of financial reports. The provisions of ASU 2023-06 are contingent upon the timing of removal of the related disclosure provisions from Regulation S-X and S-K by SEC. The Group does not expect the provisions of the standard to have a material impact on the Group's consolidated financial statements and related disclosures.

In August 2023, the FASB issued ASU 2023-05, *Business Combinations—Joint Venture Formations: Recognition and Initial Measurement* ("ASU 2023-05"), which clarifies the business combination accounting for joint venture formations. The amendments in the ASU seek to reduce diversity in practice that has resulted from a lack of authoritative guidance regarding the accounting for the formation of joint ventures in separate financial statements. The amendments also seek to clarify the initial measurement of joint venture net assets, including businesses contributed to a joint venture. ASU 2023-05 requires prospective application for all newly-formed joint venture entities with a formation date on or after January 1, 2025. Joint ventures formed prior to the adoption date may elect to apply the guidance retrospectively back to their original formation date with early adoption is permitted. The Group does not expect the adoption of ASU 2023-05 to have a material impact on the consolidated financial statements.

In March 2023, the FASB issued ASU 2023-02, *Investments—Equity Method and Joint Ventures: Accounting for Investments in Tax Credit Structures Using the Proportional Amortization Method (a consensus of the Emerging Issues Task Force)* ("ASU 2023-02"). The amendments in this update permit reporting entities to elect to account for their tax equity investments, regardless of the tax credit program from which the income tax credits are received, using the proportional amortization method if certain conditions are met. This update is effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years. The Group does not expect the adoption of ASU 2023-02 to have a material impact on the consolidated financial statements.

In March 2023, the FASB issued ASU 2023-01, *Leases: Common Control Arrangements* ("ASU 2023-01"). The amendments in the update clarify the accounting for leasehold improvements associated with common control leases. This update is effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years. The Group does not expect the adoption of ASU 2023-01 to have a material impact on the consolidated financial statements.

In December 2022, the FASB issued ASU 2022-06, *Reference Rate Reform: Deferral of the Sunset Date of Topic 848* ("ASU 2022-06"). The amendments in this update defer the sunset date of Topic 848, which provides relief to entities affected by reference rate reform. The ASU defers the sunset date of Topic 848 from December 31, 2022, to December 31, 2025. The standard is effective immediately and the Group adopted the standard in December 2022 with no material financial impact on the consolidated financial statements.

In September 2022, the FASB issued ASU 2022-04, *Liabilities -Supplier Finance Programs: Disclosure of Supplier Finance Program Obligations* ("ASU 2022-04"). The amendments in the update require that buyers disclose qualitative and quantitative information about their supplier finance programs. Interim and annual requirements include disclosure of outstanding amounts under the obligations as of the end of the reporting period, and annual requirements include a rollforward of those obligations for the annual reporting period, as well as a description of payment and other key terms of the programs. This update is effective for annual periods beginning after December 15, 2022, and interim periods within those fiscal years, except for the requirement to disclose rollforward information, which is effective for fiscal years beginning after December 15, 2023. The Group does not expect the adoption of ASU 2022-04 to have a material impact on the consolidated financial statements.

In June 2022, the FASB issued ASU 2022-03, *Fair Value Measurement Fair Value Measurement of Equity Securities Subject to Contractual Sale Restrictions* ("ASU 2022-03") which amends the guidance in Topic 820, Fair Value Measurement. The amendments in the update clarify that a contractual restriction on the sale of an equity security is not considered part of the unit of account of the equity security and, therefore, is not considered in measuring fair value. The amendments also clarify that an entity cannot, as a separate unit of account, recognize and measure a contractual sale restriction. In addition, the ASU introduces new disclosure requirements for equity securities subject to contractual sale restrictions that are measured at fair value. ASU 2022-03 is effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years for public business entities. The Group does not expect the adoption of ASU 2022-03 to have a material impact on the consolidated financial statements.

In March 2022, the FASB issued ASU 2022-02, Financial Instruments—Credit Losses: Troubled Debt Restructurings *and Vintage Disclosures* (“ASU 2022-02”). The amendments in the update address and amend areas identified by the FASB as part of its post-implementation review of the accounting standard that introduced the current expected credit losses (“CECL”) model. The amendments eliminate the accounting guidance for troubled debt restructurings by creditors that have adopted the CECL model and enhance the disclosure requirements for loan refinancings and restructurings made with borrowers experiencing financial difficulty. In addition, the amendments require disclosure of current-period gross write-offs for financing receivables and net investment in leases by year of origination in the vintage disclosures. For entities that have not yet adopted the CECL accounting model in ASU 2016-13, the effective date for the amendments in ASU 2022-02 is the same as the effective date in ASU 2016-13 (i.e., fiscal years beginning after December 15, 2022, including interim periods within those fiscal years). The Group adopted the standard from annual year started from July 1, 2023, with no material financial impact on the consolidated financial statements.

In March 2022, the FASB issued ASU 2022-01, *Derivatives and Hedging: Fair Value Hedging—Portfolio Layer Method* (“ASU 2022-01”). The amendments in the update address questions raised on ASU 2017-12, Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities. The amendments in the update expand the currently used single-layer method of hedge accounting to allow multiple layers of a single closed portfolio under the method. ASU 2022-01 is effective for fiscal years beginning after December 15, 2022, and interim periods within those fiscal years. The Group adopted the standard from annual year started from July 1, 2023, with no material financial impact on the consolidated financial statements.

In October 2021, the FASB issued ASU 2021-08, *Business Combinations: Accounting for Contract Assets and Contract Liabilities from Contracts with Customers* (“ASU 2021-08”). The amendments in the update requires contract assets and contract liabilities acquired in a business combination to be recognized and measured in accordance with ASC 606, Revenue from Contracts with Customers, on the acquisition date as if the acquirer had entered into the original contract at the same date and on the same terms as the acquiree. ASU 2021-08 is effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years for public business entities. The Group adopted the standard from annual year started from July 1, 2023, with no material financial impact on the consolidated financial statements.

Note 3 – Variable Interest Entities

On September 18, 2022, Tamboran (West) Pty Ltd (“West”) entered into a 50/50 joint operation (“JV agreement”) with DWE to form Tamboran (B1) Pty Ltd (“TB1”). In assessing the primary beneficiary of TB1, the Company determined the primary activities that most significantly impact the economic performance of TB1 include serving as the manager, determining the strategy and direction of TB1, and the power to create a budget.

The Company was appointed as the manager to manage and carry out day-to-day operations which supports the basis of Tamboran as the primary beneficiary. The Company, as manager, also prepares the work plans and budget of TB1. As such, it was determined that the Company has the power to direct TB1’s activities that most significantly impact TB1’s economic performance. As a result of the assessment performed, the results of TB1 have been included in the accompanying consolidated financial statements. TB1 has no assets that are collateral for or restricted solely to settle its obligations. The creditors of TB1 do not have recourse to the Group’s general credit.

The Company also assessed which party to the JV agreement has the obligation to absorb losses or the right to receive the benefits of the VIE that could potentially be significant to the VIE. The future profits and losses of TB1 are shared by the Company and DWE in proportion to their respective equity interest in TB1, however, to date, the Company has contributed a greater proportion of the capital and has no ability to recoup any of the excess funding the Company has made to TB1 from DWE, and therefore has a greater exposure to absorb losses.

A loan was provided to West from TR Ltd., a subsidiary of the Company. This loan was used by West to acquire its interest in TB1. On November 9, 2022, TB1 completed the acquisition of a 77.5% share of Beetaloo Basin assets, EP 76, EP 98, and EP 117. As a result of the VIE arrangement, the Company and DWE each beneficially acquired a 38.75% interest in the permits for the total undivided interest of 77.5%. Falcon Oil and Gas Australia Limited ("Falcon") holds the remaining undivided interest of 22.5% in the Beetaloo Basin assets.

On March 4, 2024, Falcon, the owner of the remaining 22.5% interest in the Beetaloo assets, capped its participation to 5% in the Beetaloo Joint Venture's second Shenandoah South well pad ("SS2"). On March 21, 2024, TB1 Operator (in which the Company has a 50% interest) agreed to pick up Falcon's interest, increasing TB1 Operator's working interest to at least 95% in the wells drilled from the SS2 well pad.

The following table summarizes the carrying amounts of TB1's assets and liabilities included in the Company's Consolidated Balance Sheet for the year ended June 30, 2024 and 2023:

	June 30,	
	2024	2023
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,488,541	$ 88,451
Trade and other receivables		
Joint Interest Billing	10,298,322	
Intercompany receivable	7,415,684	
ATO Receivable	615,480	821,979
Prepaid expenses and other current assets	1,476,094	80,806
Total current assets	21,294,121	991,236
Natural gas properties, successful efforts method:		
Unproved properties	167,998,061	102,710,385
Assets under construction - natural gas equipment	7,542,064	—
Finance lease right-of-use assets	20,697,452	—
Prepaid expenses and other non-current assets	385,215	—
Total non-current assets	196,622,792	102,710,385
TOTAL ASSETS	$217,916,913	$103,701,621
LIABILITIES		
Current liabilities		
Accounts payable and accrued expenses	$ 10,569,865	$ 11,867,753
Current portion of finance lease obligations	12,767,400	—
Total current liabilities	23,337,265	11,867,753
Finance lease obligations	14,141,713	—
Asset retirement obligations	4,174,178	3,650,758
Loan from Tamboran	113,096,572	46,257,798
Total non-current liabilities	131,412,463	49,908,556
TOTAL LIABILITIES	$154,749,728	$ 61,776,309

Note 4 – Property, Plant and Equipment & Natural Gas Properties

Natural gas properties

The Group held the following unproved gas properties as of June 30, 2024 and 2023 amounting to $230,119,448 and $163,385,971, respectively. These amounts reflect the Group's exploration projects, which are pending the determination of proven and probable reserves and were not being depleted for the years ended June 30, 2024 and 2023, respectively. These assets will be reclassified to proven gas properties upon commencement of production and then subsequently depleted.

During the years ended June 30, 2024 and 2023, the Group recognized no impairment related to unproved natural gas properties.

	Natural gas properties			
	EP 161	**EP 136 &143**	**EP 76, 98 & 117**	**Total**
Balance at July 1, 2022	$24,405,203	$31,064,789	$ —	$ 55,469,992
Additions through asset acquisition	—	—	53,205,243	53,205,243
Capital expenditure	1,547,423	22,909,877	43,755,830	68,213,130
Recognition and remeasurement of restoration assets	(133,857)	2,523,336	3,308,985	5,698,464
Royalty payments	(1,273,952)	(1,725,644)	(12,560,997)	(15,560,593)
Government grant	—	(2,579,148)	—	(2,579,148)
Effect of changes in foreign exchange rates	(826,540)	(1,394,120)	1,159,543	(1,061,117)
Balance at June 30, 2023	23,718,277	50,799,090	88,868,604	163,385,971
Reclassification of Environmental Security Bond to Other Assets	—	(563,112)	—	(563,112)
Capital expenditure	—	616,440	51,303,075	51,919,515
Recognition and remeasurement of restoration assets	—	—	72,433	72,433
Interest on finance lease liability and related depreciation of ROU assets capitalized	—	—	14,539,059	14,539,059
Effect of changes in foreign exchange rates	25,944	182,908	556,730	765,582
Balance at June 30, 2024	$23,744,221	$51,035,326	$155,339,901	$230,119,448

Assets under construction

In April 2024, the Group executed agreements for long lead items required for the Sturt Plateau Compression Facility ("SPCF") in the Beetaloo Basin. These items included essential plant components comprising of a compressor and dehydration unit that would convert future raw gas to meet sales gas quality, subject to the terms of definitive development agreements. For the year ended June 30, 2024, the Group incurred a total capital expenditure of $7,542,064 in respect of SPCF.

The 40 MMcf/d SPCF is expected to be connected to the Amadeus Gas Pipeline (AGP) via the construction of the 35-kilometer Sturt Plateau Pipeline (SPP) subject to achieving project milestones and executing further agreements.

Property, plant and equipment

	June 30, 2024	June 30, 2023
Leasehold improvements - at cost	$ 567,296	$ 541,244
Less: Accumulated depreciation	(465,052)	(343,673)
Total property, plant and equipment - net	$ 102,244	$ 197,571

Depreciation

Depreciation expense for leasehold improvements for the years ended June 30, 2024, and 2023 was $120,444 and $118,331, respectively.

Loss on assets classified as held for sale

On April 12, 2022, the Group entered into an agreement with HCI RMX, LLC to purchase rig 300, rig 301 and rig 403 (together "HCI Rigs") for a total of $21,000,000 of which $10,000,000 was paid in the year ended June 30, 2022, and the remaining $11,000,000 was paid in equal installments over the first six months ended December 31, 2022. On December 23, 2022, the HCI Rigs were classified as assets held for sale after Board approval.

Rig 300 was sold in the prior year, and during the year ended June 30, 2024, rig 301 was also sold to a third party for $444,568, net of commission expenses. The loss on sale of rig 301 was $25,605. During the one-year period subsequent to December 2022, the date at which Management classified rig 403 as held for sale, the market conditions that existed at the date the asset was classified initially as held for sale deteriorated and as a result, the remaining rig was not sold as of June 30, 2024, though was written down in June 2023 to the lower of its carrying amount and the fair value less costs to sell. As of June 30, 2024, the Group continues to meet all criteria to classify rig 403 as an asset held for sale and continues to hold the rig 403 at the lesser of its cost and fair value less costs to sell.

Note 5 – Leases

As a Lessee

The Group's operating lease activities consist of leases for office premises.

Commencing October 1, 2023, the Group entered into a new lease agreement with Lendlease IMT (OITST ST) Pty Ltd for their office premises in Barangaroo, Australia. The term of the lease is four years, with no option to renew.

On September 9, 2022, Sweetpea Petroleum Pty Ltd ("Sweetpea Petroleum"), a wholly owned subsidiary of Tamboran, entered into a drilling contract with Helmerich & Payne International Holdings LLC ("H&P") for H&P to assist the Group in carrying out its onshore drilling operations in Australia. The drilling contract grants Tamboran the right to use the drilling rig from H&P over the non-cancellable contract term of 25 months starting from July 1, 2023. Under the terms of the agreement, the Group has the right to place the drilling rig on a temporary suspension rate between wells for a period up to 270 days (the "Gap Period"). For each day of the Gap Period consumed, additional days are added to the fixed minimum term. As of June 30, 2024, the end date of the drilling contract for the current rig is mid-July 2026. The drilling contract is recognized as a finance lease under ASC 842 ("H&P Rig Lease").

The present value of the minimum future obligations was calculated based on an interest rate of 13.5% p.a., which was recognized in finance lease liabilities in the consolidated balance sheet.

The following table presents the classification and location of the Group's leases on the consolidated balance sheets:

	June 30	
	2024	2023
Right-of-use assets:		
Operating lease right-of-use assets	$ 962,052	$459,113
Finance lease right-of-use assets	20,697,452	—
	21,659,504	459,113
Lease liabilities:		
Current portion of operating lease obligations	397,999	280,962
Non- current portion of operating lease obligations	587,250	198,743
Current portion of finance lease obligations	12,767,400	—
Non-current portion of finance lease obligations	14,141,713	—
	$27,894,362	$479,705

The following table presents the components of the lease costs as at June 30, 2024 and 2023:

	For the year ended June 30,	
	2024	2023
Operating leases:		
Operating lease cost charged to profit and loss	$ 497,734	$289,970
Finance leases:		
Interest on lease liabilities	3,132,380	—
Depreciation on right-of-use assets	11,406,679	—
Total finance lease cost	14,539,059	—
Less: Lease cost capitalized to unproved properties	(14,539,059)	—
Finance lease cost charged to profit and loss	$ —	$ —

The following table presents the cash flow information related to lease payments for the years ended June 30, 2024 and 2023:

	For the year ended June 30,	
	2024	2023
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases	$ 497,734	$289,970
Financing cash flows for finance leases	5,470,379	—
	$5,968,113	$289,970

The following table presents supplemental information for the Group's non-cancellable leases for the year ended June 30, 2024, and 2023:

	For the year ended June 30,	
	2024	2023
Operating leases:		
Weighted-average remaining lease term	2.7	1.7
Weighted-average incremental borrowing rate	10.46%	3.90%
Finance leases:		
Weighted-average remaining lease term	2.1	—
Weighted-average incremental borrowing rate	13.45%	—

As of June 30, 2024, the Group's undiscounted minimum cash payment obligations for its lease liabilities are as follows:

As at June 30, 2024	Operating leases	Finance leases
Fiscal year ending June 30, 2025	$ —	$ 745,502
Fiscal year ending June 30, 2026	483,582	14,602,747
Fiscal year ending June 30, 2027	292,683	14,417,500
Fiscal year ending June 30, 2028	303,659	632,000
Thereafter	76,608	—
Total lease payments	1,156,532	30.397,749
Less: Imputed interest	(171,283)	(3,488,636)
Present value of lease liabilities	$ 985,249	$26,909,113

As a Lessor

On October 15, 2023, the Group entered into an agreement with a third party to sublease its former office premises in Manly, Australia. The commencement date of the sublease was October 1, 2023, with a lease term of 17 months. Sublease income for the nine months ended June 30, 2024, was $230,038 and is included within "Other expenses, net" on the Group's consolidated statements of operations and comprehensive loss. There have been no indications of impairment related to the underlying right-of-use asset.

Note 6 – Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses included in current liabilities consists of the following:

	June 30, 2024	June 30, 2023
Accounts payable	$ 6,619,320	$ 4,205,015
Accrued payroll	13,216	435,987
Compensated absences	668,825	396,949
Defined contribution superannuation payable	8,164	7,520
Accrued capital expenditure	4,318,703	7,115,806
Accrued expenses	3,204,371	2,310,386
	$14,832,599	$14,471,663

Note 7 – Asset Retirement Obligations

The Group recognizes the liability for an asset retirement obligation at their estimated fair value in the period in which the obligation originates. Fair value is estimated using the present value technique (level 2) based on a number of observable inputs including estimates and assumptions such as future retirement costs, future inflation rates and the Group's credit-adjusted risk-free interest rate.

The Group capitalized the present value of the estimated asset retirement obligations as a part of the carrying amount of the related natural gas properties. The liability has been accreted to its present value for the year ended June 30, 2024.

The reconciliation of changes in asset retirement obligations is as follows:

	For the years ended June 30,	
	2024	2023
Beginning asset retirement obligations	$7,182,739	$ 903,169
Associated with acquisitions	—	4,143,966
Liabilities incurred	72,433	3,842,925
Accretion expense	891,961	600,959
Revision of estimates	—	(2,288,427)
Effect of changes in foreign exchange rates	(6,141)	(19,853)
Long-term asset retirement obligations	$8,140,992	$ 7,182,739

Note 8 – Convertible Note

On June 4, 2024, Tamboran issued a "5.5% Convertible Senior Note Due 2029" (the "Note") with an initial principal amount of $9,390,500 to H&P. The Note was issued in exchange for the full cancellation of the existing H&P Accounts Payable amount of $7,785,000 (the "Proceeds"). The Note bore an interest rate of 5.5% per annum and was payable on July 1, 2029 upon H&P's demand (unless otherwise redeemed, converted earlier). The interest accrued on the Note was payable quarterly.

The Note did not include any financial covenants and was subject to acceleration at the option of H&P or automatic acceleration upon the occurrence of specified events of default. The Note was subject to the following conversion features:

- In the event Tamboran completes a qualified IPO (as defined in the note purchase agreement), the outstanding principal and unpaid accrued interest will automatically convert into the common stock of Tamboran.
- In the event Tamboran completes a non-qualified IPO (as defined in the note purchase agreement), the outstanding principal and unpaid accrued interest will be converted at the option of H&P into the common stock of Tamboran.

The number of shares of Tamboran's common stock with respect to conversion of the Note is determined to be the quotient obtained by dividing (a) the Note principal amount, by (b) the product of (i) the IPO Conversion Price and (ii) one minus the discount rate of 20%.

On June 28, 2024, upon the IPO (Note 1), the fair value of outstanding principal and unpaid accrued interest of the Note amounting to $11,738,112 was converted into 489,088 shares of Tamboran's common stock (Refer Note 9).

Tamboran elected the fair value option to account for the Note. The Note was initially recorded at fair value of $11,668,980 and was subsequently remeasured at fair value upon conversion. The fair value of the Note at the time of conversion was determined to be equal to $11,738,112. The change in fair value of the Note were recognized as a component of other income (expense), net in the consolidated statements of operations and comprehensive loss. During the year ended June 30, 2024, Tamboran recognized $3,883,980 as a loss on extinguishment of payables to H&P in exchange of issuance of the Note, a loss of $34,700 as change in fair value of the Note and a loss of $34,432 as interest expense on the Note.

The following table presents a roll-forward of the aggregate fair value of the Note for which fair value is determined by Level 3 inputs:

	Year ended June 30, 2024
Balance at July 1, 2023	$ —
Initial fair value at issuance	11,668,980
Change in fair value plus accrued interest	69,132
Settlement at the time of conversion	(11,738,112)
Balance at June 30, 2024	$ —

Note 9 – Stockholders' Equity

	2024 Common Stock	2023 Common Stock	2024 Amount	2023 Amount
Common stock issued and outstanding, par value	13,915,524	7,080,054	$13,915	$7,080

Movements in common stock:

	Date	Tamboran Common Stock	CDIs	Issue price	Details	Net Proceeds
Balance at July 1, 2022		3,736,798	747,359,518			$167,562,860
Capital raise	September 2022	934,199	186,839,878	$ 0.14	25,370,240	
Capital raise	October 2022	2,328,062	465,612,410	$ 0.13	61,150,740	
Capital raise	October 2022	80,995	16,198,945	$ 0.13	2,183,942	
Less: Transaction costs					(4,090,117)	84,614,805
Balance at June 30, 2023		7,080,054	1,416,010,751			$252,177,665
Capital raise	July and August 2023	1,503,309	300,661,820	$ 0.12	$ 36,151,220	
Capital raise	December 2023	1,274,525	254,905,029	$ 0.11	$ 27,660,258	
Capital raise	January 2024	443,548	88,709,600	$ 0.11	$ 9,328,083	
Capital raise	June 2024	3,125,000	N/A	$24.00	$ 75,000,000	
Capital raise*	June 2024	489,088	N/A	$24.00	$ 11,738,112	
Less: Transaction costs					$(15,131,161)	144,746,512
Balance at June 30, 2024		13,915,524	2,060,287,200			**$396,924,177**

* *Refer Note 8*

As referred to in Note 1, all ordinary shares of TR Ltd. have been transferred to Tamboran Resources Corporation and pursuant to the Scheme, the Company issued to the shareholders of TR Ltd. one CDI for each ordinary share of TR Ltd. as held on the Scheme record date. Each CDI represents 1/200th of a share of common stock. All share and per share data presented in our consolidated financial statements have been retroactively adjusted to reflect the Exchange Ratio.

Holders of common stock of the Company are entitled to participate in any dividends declared and any proceeds attributable to common stockholders should the Company be wound up, in proportions that consider both the number of shares held and the extent to which those common stock are paid up. Holders of shares of the Company's common stock are entitled to one vote for each share held of record on all matters on which stockholders are entitled to vote generally. The holders of the CDIs are the beneficial owners of, and generally have the same voting, economic and other rights as holders of our common stock, although they are required to exercise those rights indirectly through a depositary who holds shares of common stock.

No dividends have been declared or paid by the Company through June 30, 2024 and 2023.

Note 10 – Stock-based Compensation

Historically, incentives offered to the Board, employees and consultants have included a combination of options, warrants, and employee share scheme ("ESS") instruments having either fixed exercise prices or variable prices based on multiples of the fair market value of the enterprise at grant date.

Equity incentive plan

The Group has adopted the Equity Incentive Plan in order to assist in the motivation and retention of selected employees and directors. Below is a summary of the terms and conditions of the options issued under the Equity Incentive Plan.

Total number of options issued under the Equity Incentive Plan	Vesting condition	Exercise price and expiry date
10,734,584 options	Fully vested	A$0.32 per option expiring on May 20, 2026
7,416,667 options	Fully vested	A$0.2367 expiring on May 20, 2026
39,350,000 milestone options	(1) 25% of milestone options vest if the 90-day VWAP is greater than or equal to A$1.00 per share (2) 25% of milestone options vest if the 90-day VWAP is greater than or equal to A$1.50 per share (3) 25% of milestone options vest if the 90-day VWAP is greater than or equal to A$2.00 per share (4) 25% of milestone options vest if the 90-day VWAP is greater than or equal to A$2.50 per share	A$0.40 per milestone option expiring on May 20, 2026 or, if the milestone options vest, the day that is 5 years after the date they vest as determined by the Board.

If there is any reconstruction of the issued shares of the Company, the rights of the optionholders may be varied to comply with the ASX Listing Rules which apply to the reconstruction at the time of the reconstruction. As a result of the reorganization of the Group referred to in Note 1, all previously issued options over shares in TR Ltd. became options over CDIs in the Company.

Each option entitles the optionholder a right to buy one CDI upon exercise of the option and is exercisable at any time on or prior to May 20, 2026. CDIs issued on exercise of the options will rank equally with the then CDIs of the Company. The options are not transferable.

The options may be exercised by notice in writing to the Company and payment of the relevant exercise price for each option being exercised. The Company will not apply to ASX for quotation of the options however it will apply to ASX for quotation of the CDIs issued upon the exercise of the options.

There are no participation rights or entitlements inherent in the options and holders will not be entitled to participate in new issues of capital offered to stockholders.

If the Company makes a bonus issue of common stock or other securities to existing stockholders (other than an issue in lieu or in satisfaction of dividends or by way of dividend reinvestment) the number of CDIs which must be issued on the exercise of an option will be increased by the number of CDIs which the optionholder would have received if the optionholder had exercised the option before the record date for the bonus issue.

If the Company makes an issue of CDIs pro rata to existing stockholders (other than an issue in lieu or in satisfaction of dividends or by way of dividend reinvestment) the exercise price of an option will be reduced according to the ASX Listing Rules.

The following table summarizes CDI option activity for the years ended June 30, 2024 and 2023:

2024

Grant date	Expiry date	Exercise price	Balance at the start of the year	Granted	Exercised	Expired/ forfeited/ other	Balance at the end of the year
May 20, 2021	May 20, 2026	A$ 0.2367	7,416,667	—	—	—	7,416,667
May 20, 2021	May 20, 2026	A$ 0.3200	10,734,584	—	(29)	—	10,734,555
May 20, 2021	May 20, 2026	A$ 0.4000	16,000,000	—	—	—	16,000,000
October 28, 2021	May 20, 2026	A$ 0.4000	18,850,000	—	—	(3,000,000)	15,850,000
May 17, 2022	May 20, 2026	A$ 0.4000	400,000	—	—	—	400,000
June 14, 2022	May 20, 2026	A$ 0.4000	1,250,000	—	—	—	1,250,000
November 30, 2022	May 20, 2026	A$ 0.4000	2,850,000	—	—	—	2,850,000
			57,501,251	—	(29)	(3,000,000)	54,501,222
Weighted average exercise price			A$ 0.3634	A$ —	A$0.3200	A$ 0.4000	A$ 0.3620

2023

Grant date	Expiry date	Exercise price	Balance at the start of the year	Granted	Exercised	Expired/ forfeited/ other	Balance at the end of the year
May 20, 2021	May 20, 2026	A$ 0.2367	7,416,667	—	—	—	7,416,667
May 20, 2021	May 20, 2026	A$ 0.3200	10,734,584	—	—	—	10,734,584
May 20, 2021	May 20, 2026	A$ 0.4000	16,000,000	—	—	—	16,000,000
October 28, 2021	May 20, 2026	A$ 0.4000	20,750,000	—	—	(1,900,000)	18,850,000
May 17, 2022	May 20, 2026	A$ 0.4000	400,000	—	—	—	400,000
June 14, 2022	May 20, 2026	A$ 0.4000	1,250,000	—	—	—	1,250,000
November 30, 2022	May 20, 2026	A$ 0.4000	—	2,850,000	—	—	2,850,000
			56,551,251	2,850,000	—	(1,900,000)	57,501,251
Weighted average exercise price			A$ 0.3634	A$ 0.4000	A$—	A$ 0.4000	A$ 0.3640

Set out below are the options exercisable at the end of the financial year:

		Number at June 30,	
Grant date	Expiry date	2024	2023
20/05/2021	20/05/2026	7,416,667	7,416,667
20/05/2021	20/05/2026	10,734,555	10,734,584
		18,151,222	18,151,251

The weighted average remaining contractual life of options outstanding as of June 30, 2024 and 2023, was 0.32 years and 2.89 years, respectively.

For the milestone options granted during the year ended on June 30, 2023, the Monte-Carlo valuation model inputs used to determine the fair value at the grant date, are as follows:

Grant date	Expiry date	CDI price at grant date	Exercise price	Expected volatility	Dividend yield	Risk-free interest rate	Fair value at grant date
October 28, 2021	May 20, 2026	A$ 0.4000	A$ 0.4000	65.0000%	—	1.4809%	A$ 0.1815
October 28, 2021	May 20, 2026	A$ 0.4000	A$ 0.4000	65.0000%	—	1.4809%	A$ 0.1630
October 28, 2021	May 20, 2026	A$ 0.4000	A$ 0.4000	65.0000%	—	1.4809%	A$ 0.1381
October 28, 2021	May 20, 2026	A$ 0.4000	A$ 0.4000	65.0000%	—	1.4809%	A$ 0.1188
May 17, 2022	May 20, 2026	A$ 0.2800	A$ 0.4000	70.0000%	—	3.1430%	A$ 0.1050
May 17, 2022	May 20, 2026	A$ 0.2800	A$ 0.4000	70.0000%	—	3.1430%	A$ 0.0861
May 17, 2022	May 20, 2026	A$ 0.2800	A$ 0.4000	70.0000%	—	3.1430%	A$ 0.0700
May 17, 2022	May 20, 2026	A$ 0.2800	A$ 0.4000	70.0000%	—	3.1430%	A$ 0.0577
June 14, 2022	May 20, 2026	A$ 0.2300	A$ 0.4000	70.0000%	—	3.7490%	A$ 0.0807
June 14, 2022	May 20, 2026	A$ 0.2300	A$ 0.4000	70.0000%	—	3.7490%	A$ 0.0651
June 14, 2022	May 20, 2026	A$ 0.2300	A$ 0.4000	70.0000%	—	3.7490%	A$ 0.0528
June 14, 2022	May 20, 2026	A$ 0.2300	A$ 0.4000	70.0000%	—	3.7490%	A$ 0.0432
November 30, 2022	May 20, 2026	A$ 0.2600	A$ 0.4000	70.0000%	—	3.1160%	A$ 0.0871
November 30, 2022	May 20, 2026	A$ 0.2600	A$ 0.4000	70.0000%	—	3.1160%	A$ 0.0677
November 30, 2022	May 20, 2026	A$ 0.2600	A$ 0.4000	70.0000%	—	3.1160%	A$ 0.0529
November 30, 2022	May 20, 2026	A$ 0.2600	A$ 0.4000	70.0000%	—	3.1160%	A$ 0.0419

Note 11 – Income Taxes

Deferred income taxes reflect the net tax effects of (a) temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes, and (b) operating losses and tax credit carryforwards.

In October 2021, more than 130 countries agreed to implement Pillar 2, a plan introduced by the Organization for Economic Co-operation and Development ("OECD") providing for a global minimum tax rate of 15% (calculated on a country-by-country basis) for those companies having consolidated revenue of at least €750 million. The implementation of the Pillar 2 global minimum tax rules is intended to apply for tax years beginning in 2024. The main purpose of such rules is to minimize tax base erosion and profit shifting from higher tax jurisdictions to lower tax jurisdictions by multi-national companies. On February 1, 2023, the FASB indicated that they view the minimum tax ("Top-Up Tax") imposed under Pillar 2 as an alternative minimum tax, and as such, it should be recognized in the period incurred versus recognizing or adjusting deferred tax assets and liabilities. On February 2, 2023, the OECD issued various administrative guidance including transitional safe harbor rules available in conjunction with the implementation of the Pillar 2 global minimum tax. Based upon the current OECD rules and administrative guidance, the Group does not anticipate being subject to material Top-Up Taxes as various tax jurisdictions begin enacting such legislation. The Group is continuing to monitor the potential impact of the Pillar 2 proposals and developments on the consolidated financial statements and related disclosures, including eligibility for any transitional safe harbor rules.

Significant components of deferred tax assets (liabilities) are as follows:

	June 30, 2024	June 30, 2023
Deferred tax assets:		
Asset retirement obligations	$ 267,588	$ 90,620
Transaction costs arising on common stock issued	2,435,335	2,640,335
Tax losses carried forward	81,982,925	57,624,887
Leases	1,891,146	6,178
Employee benefits	225,430	160,425
Other	129,208	245,745
Total deferred tax assets	86,931,633	60,768,190
Deferred tax liabilities:		
Leases	—	—
Exploration assets	(59.761,789)	(43,424,967)
Total deferred tax liabilities	(59,761,789)	(43,424,967)
Total net deferred tax assets	27,169,843	17,343,223
Less: Valuation allowance	(27,169,843)	(17,343,223)
Net deferred tax assets	$ —	$ —

The Australian statutory tax rate is 30%. The income tax provision differs from the amount of income tax determined by applying Australian income tax rate to pretax income as follows:

	For the years ended June 30, 2024	For the years ended June 30, 2023
Loss before income tax expense	$(23,850,769)	$(32,195,616)
Tax at the Australian statutory rate of 30% (2023: 30%)	(7,155,231)	(9,658,685)
Permanent differences	173,863	3,342,216
Earnings in jurisdictions taxed at rates different from the statutory tax rate	236,616	180,269
Valuation allowance recognized	6,744,752	6,136,200
Income tax expense	$ —	$ —

The Group has no income tax expense due to operating losses incurred for the years ended June 30, 2024 and 2023. The Group has provided a full valuation allowance on the net deferred tax asset because management has determined that it is more-likely-than-not that the Group will not earn income sufficient to realize the deferred tax assets during a foreseeable future period. Management will continue to assess the potential for realizing deferred tax assets based upon income forecast data and the feasibility of future tax planning strategies and may record adjustments to the valuation allowance against deferred tax assets in future periods, as appropriate, that could have a material impact on the statement of operations.

As of June 30, 2024, the Group had accumulated tax losses related to a foreign tax jurisdiction in Australia of $81,117,531 and US net operating loss carry forward of $865,394. The losses are reflected at the relevant countries statutory corporate rate of 30% (Australia) and 21% (USA). The foreign tax losses carried forward, which have a valuation allowance against them, can be carried forward indefinitely subject to satisfying certain Australian legislative requirements. The Company’s net operating loss carry forwards in the USA can be carried forward indefinitely.

Note 12 – Loss per Share

Basic net loss per share applicable to common stockholders is computed by dividing earnings applicable to common stockholders by the weighted average number of common shares outstanding. Diluted loss per share assumes the conversion of any convertible securities using the treasury stock method.

The computations for basic and diluted loss per share are as follows:

	For the years ended June 30,	
	2024	**2023**
Numerator:		
Net loss after income tax attributable to Tamboran Resources Corporation stockholders	$(21,918,471)	$(32,033,347)
Denominator:		
Weighted average number of common stock outstanding, basic and diluted	9,450,244	6,052,044
Net loss per share, basic and diluted	$ (2.319)	$ (5.293)

The Company's potentially dilutive shares, which include outstanding common stock options, have not been included in the computation of diluted net loss per share for the years ended June 30, 2024 and 2023 as the result would be anti-dilutive.

Note 13 – Commitments and Contingencies

From time to time, the Group may be subject to various claims, title matters and legal proceedings arising in the ordinary course of business, including environmental contamination claims, personal injury and property damage claims, claims related to joint interest billings and other matters under natural gas operating agreements and other contractual disputes. The Group maintains general liability and other insurance to cover some of these potential liabilities. All known liabilities are fully accrued based on the Group's best estimate of the potential settlement amount. While the outcome and impact on the Group cannot be predicted with certainty, the Group believes that its ultimate liability with respect to any such matters will not have a significant impact or material adverse effect on its financial positions, results of operations or cash flows. Results of operations and cash flows, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Capital commitments

	June 30,	
	2024	**2023**
Committed at the reporting date but not recognized as liabilities, payable:		
Sweetpea Petroleum Pty Ltd	$23,283,360	$42,465,150
EP 161	2,649,600	2,652,000
Beetaloo Joint Venture	62,642,340	54,208,538
Midstream	1,971,843	—

Sweetpea Petroleum Pty Ltd

Sweetpea Petroleum's minimum committed spend, is $23,283,360 which is related to two licenses, EP 136 with total commitments of $14,076,000 and EP 143 with total commitments of $9,207,360.

In relation to EP 136, the Department of Industry, Tourism and Trade (DITT) granted a five-year extension in July 2024 for the period July 24, 2025 to July 23, 2030. As the license was held by Sweetpea Petroleum at June 30, 2024, the commitments agreed with DITT for the new license period are reported here. The year 1 minimum work requirement is $165,600 to undertake planning, design, contracting, and operational readiness by July 2026. The minimum expenditure for Permit Years 2-5 inclusive (July 2026 to July 2030) is $13,910,400, including drilling and multistage fracture stimulation of one horizontal well in Permit Year 2, followed by evaluation of the results and development of viability assessments in the subsequent years.

Sweetpea Petroleum has current Year 2 minimum work requirements in EP 143 which include various desktop evaluations including subsurface studies, acquire, process and interpret 125km of 2D seismic survey and finalize land access negotiations with pastoralist for regulated activities for a minimum expenditure of $1,722,240 by April 2025. The remaining committed spend for EP 143 of $7,485,120 relates to Year 3 to Year 5 inclusive with minimum work requirements over the period May 2025 to April 2028.

EP 161

For the McArthur working interest, we are obligated to contribute our share of expenses to uphold our stake in EP 161. Our commitment through March 2026 is approximately $2,649,600 based on the minimum work requirements. There are no minimum commitment requirements after March 2026.

Beetaloo Joint Venture

The terms of the Beetaloo Joint Venture necessitate specific minimum work obligations through to May 2028. These commitments include an expected spend of $62,642,340 related to drilling and multi-stage hydraulic fracturing of six wells, a 2D seismic survey in each license and subsurface studies, with expenditure across EP 76 of $21,304,440, EP 98 of $20,033,460 and EP 117 of $21,304,440.

There is a minimum work requirement of $7,286,400 in EP 98 before May 2025 to undertake drilling and multistage fracture stimulation of one horizontal well and undertake further subsurface studies including planning, design, contracting, and operational readiness for 2D Seismic acquisition.

Midstream

Tamboran and Daly Waters Energy (DWE) are in the process of forming a new joint venture which will own the Sturt Plateau Compression Facility (SPCF), each with a 50% interest. Procurement of the long lead items for the compressor package and dehydration package was placed in June 2024 with progress payments of $1,971,843 required prior to the end of 2025.

Environmental

The Group's operations are subject to risks normally associated with the drilling, completion and production of oil and gas, including blowouts, fires, and environmental risks such as oil spills or gas leaks that could expose the Group to liabilities associated with these risks.

In the Group's acquisition of existing or previously drilled well bores, the Group may not be aware of prior environmental safeguards, if any, that were taken at the time such wells were drilled or during such time the wells were operated. The Group maintains comprehensive insurance coverage that it believes is adequate to mitigate the risk of any adverse financial effects associated with these risks.

However, should it be determined that a liability exists with respect to any environmental cleanup or restoration, the liability to cure such a violation could still fall upon the Group. No claim has been made, nor is the Group aware of any liability which the Group may have, as it relates to any environmental cleanup, restoration, or the violation of any rules or regulations relating thereto except for the matter discussed above.

Legal proceedings

The Group is a party to legal proceedings encountered in the ordinary course of its business. While the ultimate outcome and impact to the Group cannot be predicted with certainty, in the opinion of management, it is remote that these legal proceedings will have a material adverse impact on the Group's consolidated financial condition, results of operations or cash flows.

Note 14 – Related Party Transactions

The Group had related party transactions with two shareholders, H&P and Bryan Sheffield, for the years ended June 30, 2024 and 2023.

H&P

During the year ended June 30, 2023, the Group entered into a strategic alliance with H&P and secured a $15,000,000 equity investment from H&P. In connection with the investment, a member of the management of H&P was appointed as a director of the Company. The strategic alliance resulted in H&P supporting the Group's development plans in the Northern Territory through their equity investment in the business while at the same time executing on H&P's strategy to gain more international exposure through the use of drilling rigs in Australia.

The Group has executed a lease contract for one H&P FlexRig® until July 2026 with an option to lease up to five additional rigs over the next ten years. The drilling contract is recognized as a finance lease under ASC 842 (Refer to Note 5). As of June 30, 2024, $647,921 remains unpaid related to June standby costs.

On June 4, 2024, Tamboran issued the Note with an initial principal amount of $9,390,500 to H&P. The Note was issued in exchange for the full cancellation of the Existing H&P Accounts Payable amount of $7,785,000 (Refer Note 8). On June 28, 2024, the Note was converted into 489,088 shares of Tamboran's common stock (Refer Note 9).

In addition to the rig contract and the settlement of the convertible note as disclosed in the notes above, the Group incurred $1,420,316, relating to a combination of mobilization drilling, labor and rig move costs.

Bryan Sheffield

During the year ended June 30, 2024, the Group transacted with DWE, an entity controlled by Mr. Sheffield who has been a shareholder in the Company since November 2021.

During the year ended June 30, 2023, DWE formed a 50/50 joint venture with the Group to acquire Origin Energy's exploration permits EP 76, 98 and 117 in the Beetaloo Basin (collectively known as the Beetaloo Joint Venture). The result of this transaction is that DWE obtained a beneficial ownership of 38.75% in the Beetaloo Joint Venture. The Group also obtained a 38.75% beneficial ownership in the Beetaloo JV during the period ended June 30, 2023 and is the operator of these permits.

On June 3, 2024, a Deed of Amendment and Restatement (the "Amended Agreement") was signed by West and DWE, the owners of TB1. The Amended Agreement incorporates matters agreed upon in the initial JV agreement and the Joint Venture and Shareholder Agreement ("JVSA") Amendment Letter between the parties dated June 21, 2023 ("Amendment Letter").

The Amended Agreement requires Tamboran as Manager to use all reasonable endeavours to apply for a Production License, where justified by Appraisal Results, by December 31, 2024. Pursuant to the Amended Agreement, if the parties do not implement the Checkerboard Strategy by December 31, 2024 due to either:

(i) ministerial approval to effectuate the Checkerboard Strategy having not been obtained; or (ii) the New Area Joint Venture having not been approved and given effect to under the JOA, then, by no later than February 15, 2025, TBN shall either: (a) pay DWE a cash payment of $7,500,000; or (b) issue CDIs to DWE with a value of $15,000,000, with a deemed issue price per share equivalent to the volume weighted average price of CDIs traded on the ASX at the time during the 30 days on which sales in CDIs were recorded prior to December 31, 2024.

DWE agreed to waive the payment obligation above if Tamboran issued Common Stock in the aggregate amount of $7,500,000 based on the initial public offering price to DWE, or its nominee.

Tamboran intends to issue to DWE, a portfolio company of Formentera Partners, LP (a private investment firm co-founded and managed by Bryan Sheffield), or its nominee, $7,500,000 in shares of Tamboran's common stock, in satisfaction of certain obligations under a joint venture agreement between Tamboran and DWE. As of June 30, 2024 and at the time of issuance of these consolidated financial statements, the issuance of these shares is awaiting shareholder approval.

During the year ended June 30, 2024, the Group issued cash call requests totalling $26,064,339 to DWE to fund their share of costs for the Beetaloo Joint Venture. As of June 30, 2024, the Group had unpaid cash calls owing from DWE in the amount of $8,857,842.

Note 15 – Subsequent Events

IPO from listing on NYSE

In July 2024, the underwriters partially exercised their over-allotment option granted in connection with our IPO to purchase an additional 308,750 shares of common stock, resulting in gross proceeds of $7.4 million and net proceeds to us of $7.0 million, after deducting the underwriting discount.

Variation to EP 136 minimum requirements

The DITT granted a five-year extension for EP 136 for the period July 24, 2025 to July 23, 2030 with minimum work requirements of $23,283,260 including the drilling and multistage fracture stimulation of one horizontal well in Permit Year 2.

Progress on NTLNG development

In July 2024, the Group executed an interim agreement with the Northern Territory Government for exclusive access to the Wirraway North land at Middle Arm for NTLNG, subject to meeting certain milestones. This replaces the Do Not Deal letter agreement previously executed with the Northern Territory Government and will be the active agreement that secures the land for the Group until just before it considers a Final Investment Decision (FID) on NTLNG.

In August 2024, the Group appointed Bechtel to undertake pre-FEED engineering services for NTLNG for $4,620,000 until the end of March 2025.

Shenandoah South Pilot Project

In August 2024, the Group spudded the Shenandoah South well SS2-2H using the H&P FlexiRig 469.

Also in August 2024, the Group signed a contract with Liberty for the fracture stimulation of the six wells planned to be drilled from the Shenandoah South 2 well pad, being SS2-2H and SS2-1H, during 2024, and plus the four wells planned for 2025.

Employee Incentive Awards

On August 6, 2024, the Company granted 47,400 Restricted Stock Units (“Retention Awards”) to its employees in Australia and U.S. The Retention Awards granted to Australian employees entitle them to CDIs representing 39,250 shares of common stock. Similarly, the Retention Awards granted to U.S. employees entitle them to 8,150 shares of common stock. The vesting conditions state that all Retention Awards will vest in full on December 31, 2025, provided the employee remain in service as of the vesting date.

On August 6, 2024, the Company also granted 795,000 Restricted Stock Units (“IPO Awards”) to its employees in Australia and U.S. The IPO Awards granted to Australian employees entitle them to CDIs representing 620,000 shares of common stock. Similarly, the IPO Awards granted to U.S. employees entitle them to 175,000 shares of common stock. The IPO Awards will vest in following three tranches:

- Tranche 1 – 397,500 IPO Awards granted to Australian and U.S. employees will vest in full on July 3, 2027, provided the employee remain in service as of the vesting date.
- Tranche 2 – 98,750 IPO Awards granted to Australian and U.S. employees will vest subject to the completion of the Group’s Phase 1 Development Plan to establish first production of the Shenandoah South Pilot Project and establish first production of 40 TJ/d measured by completion of the milestones (“Vesting Trigger Conditions”). Full vesting of Tranche 2 may occur at any time between July 3, 2027, and July 3, 2029, should the Vesting Trigger Conditions be satisfied, or unless otherwise determined by the Board of the Company.
- Tranche 3 – 298,750 IPO Awards granted to Australian and U.S. employees will vest subject to the Company’s Total Shareholder Return (“TSR”) reaching or exceeding the 75th percentile of the Benchmark Index TSR between July 3, 2027, and July 3, 2029. TSR will be measured against the S&P SmallCap 600 Energy (or any other market index determined by the Board in their sole discretion) (“Benchmark Index”) over the same performance measurement period.

Rig 403 sale

In September 2024, the Group entered into an exclusivity agreement for the sale of Rig 403 for $8.5 million gross (excluding sales commission of 6%), which includes a $400,000 non-refundable payment for a 30-day exclusivity period.

The Group has evaluated its subsequent events occurring after June 30, 2024, through September 20, 2024, which represents the date the audited financial statements were available to be issued. No further material subsequent events have been identified that would require disclosure in these audited financial statements.

Note 16 – Supplemental Oil and Gas Disclosures (unaudited)

The following information was prepared in accordance with the FASB’s Accounting Standards Update no. 2010-03, *Extractive Activities – Oil and Gas (ASC 932)*. The supplementary information summarized below presents the results of natural gas and oil activities for the Group in accordance with the successful efforts method of accounting for production activities.

The Group’s oil and natural gas activities for financial years 2024 and 2023 were located solely in Australia.

Costs incurred in natural gas exploration and development

Costs incurred in natural gas producing activities for the years ended on June 30, 2024 and 2023 were as follows:

	For the years ended June 30,	
	2024	2023
Property acquisition costs:		
Proved	$ —	$ —
Unproved	—	53,205,243
Exploration costs:		
Geological and geophysical	2,161,424	2,793,036
Development costs	74,000,638	30,770,172
Total cost incurred	76,162,062	86,768,451
Asset retirement obligations	72,433	5,698,464
Total cost incurred	$76,234,495	$ 92,466,915

Capitalized costs

Capitalized costs consist of Group's properties, equipment, and facilities for natural gas exploration projects, which are pending the determination of proven or probable reserves. Capitalized costs for unproved properties include costs for acquiring oil and natural gas properties where no proved reserves have been identified, including costs of exploratory wells that are in the process of drilling or in active completion, and costs of exploratory wells suspended or waiting on completion.

The table below sets forth capitalized costs, impairment, and depreciation, depletion and amortization relating to the Group's oil and natural gas properties as of June 30, 2024 and 2023:

	June 30,	
	2024	2023
Natural gas properties, successful efforts method:		
Unproved properties	$230,119,448	$163,385,971
Accumulated impairment to unproved properties	—	—
Net unproved properties	$230,119,448	$163,385,971
Assets under construction - natural gas equipment	7,542,064	—
	$237,661,512	$163,385,971

In conjunction with the capital raise in September 2022, Tamboran granted Daly Waters Royalty, an ORRI of 2.34358% to the Petroleum (as defined in the *Petroleum Act 1984* (NT)) produced from each of the permits above. The payment received from Daly Waters Royalty for the ORRI grant has been offset against the asset to which the payment related. While the above permits are subject to royalties, Tamboran has excluded all royalties from contingent payments and the initial measurement of the assets acquired as well as royalties for existing permits. Tamboran will recognize a liability for royalties only when the contingent payment crystallizes.

Natural gas reserves

Proved reserves are estimated quantities of natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs using existing economic and operating conditions. Estimating natural gas reserves is complex and inexact because of the numerous uncertainties inherent in the process. The process of estimating proved reserves requires certain economic assumptions, including, but not limited to, natural gas prices, drilling, completion and operating expenses, capital expenditures and taxes. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

All of the Group’s exploration and evaluation projects are pending the determination of proven or probable reserves. As such, the estimates of Group’s total proved reserves were nil as of June 30, 2024 and 2023.

DIRECTORS AND OFFICERS

Directors	Officers
Fredrick Barrett	**Joel Riddle**
Chief Executive Officer and Chairman of the Board (retired), Bill Barrett Corporation	*Managing Director and Chief Executive Officer*
Patrick Elliott	**Eric Dyer**
Founder and Director (retired), Eastern Star Gas and SAPEX Limited	*Chief Financial Officer*
Stephanie Reed	**Faron Thibodeaux**
Partner, Formenera Partners	*Chief Operating Officer*
John Bell	
Senior Vice President of International and Offshore Operations, Helmerich & Payne, Inc.	
Ryan Dalton	
Executive Vice President and Chief Financial Officer (retired), Parsley Energy, Inc.	
Andrew Robb	
Minister for Trade, Investment, and Tourism (retired), Australian Government	
Joel Riddle	
Managing Director and Chief Executive Officer, Tamboran Resources corporation	
Richard Stoneburner	
Partner and Senior Advisor, Pine Brook Partners	
David Siegel	
Senior Advisor, Apollo Global Management	

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RESOURCES

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