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, 2026
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

(Exact name of Registrant as specified in its Charter)

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

As of December 31, 2025, the aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates as of such date was $468,176,582. As of September 23, 2026, the number of shares outstanding of the registrant's common stock was 34,960,006.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Tamboran Resources Corporation Proxy Statement for the 2026 Annual Meeting of stockholders ("2026 Proxy Statement") are incorporated by reference into Part III hereof.

TABLE OF CONTENTS

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.

"*Arrangement*" refers to the Falcon Acquisition.

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

"*Beetaloo*" or "Beetaloo Basin" 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 Australia (22.5% non-operated working interest), which was acquired by Tamboran on May 28, 2026.

"*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.

"*CO_2*" refers to carbon dioxide.

"*CO_2-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 I, LP, which is managed by Formentera Australia Fund I GP, LP, a private equity firm of which Mr. Bryan Sheffield serves as managing partner.

"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.

"*Exchange Act*" refers to the Securities Exchange Act of 1934, as amended.

"*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.

"farm-in agreement" refers to an agreement under which the owner of a working interest in a 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 "*Falcon Canada*" refers to Falcon Oil and Gas Limited, a corporation incorporated under the Business Corporations Act (British Columbia).

"*Falcon Acquisition*" refers collectively to (a) the acquisition by Tamboran (Beetaloo) Pty Ltd from Falcon of approximately 98.1% of the issued and outstanding equity interests of Falcon Oil & Gas Australia Limited ("Falcon Australia" or "FOGA") and (b) the acquisition by Tamboran Resources Investments Holding Corporation from Falcon of all of the issued and outstanding equity interests of TXM Oil and Gas Exploration Kft. ("Falcon Hungary"), Falcon Oil & Gas Ireland Limited ("Falcon Ireland"), Falcon Oil & Gas Holdings Ireland Limited ("Falcon Holdings") and Falcon Exploration and Production South Africa (Pty) Ltd ("Falcon South Africa").

"*Falcon Australia*" or "*FOGA*" refers to Falcon Oil & Gas Australia Ltd, previously a wholly owned subsidiary of Falcon

"*Falcon Entities*" refers collectively to Falcon Australia, Falcon Hungary or TXM, Falcon Ireland, Falcon Holdings and Falcon South Africa.

"*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 & 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.

"*JOBS Act*" refers to the Jumpstart Our Business Startups Act, as amended.

"*LNG*" refers to liquefied natural gas.

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

"*MMBoe*" refers to one million barrels of oil equivalent.

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

"*NYSE*" refers to the New York Stock Exchange.

"*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.

"*Securities Act*" refers to the Securities Act of 1933, as amended.

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

"*SOX*" refers to the Sarbanes-Oxley Act of 2002, as amended.

"*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 2026" refer to the twelve months ended June 30, 2026. References to "dollars," "$" and "U.S. dollars" refer to United States dollars; and references to "Australian dollars" and "A$" 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 Years	
	2026	2025
A$1.00	$ 0.68	$ 0.65

Cautionary Note Regarding Emerging Growth Company Status

Section 102(b)(1) of the 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 benefits of strategic transactions (including acquisitions and divestitures), anticipated events and trends, the economy and other future conditions. Forward-looking statements can be identified by words such as: "anticipate," "intend," "plan," "goal," "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 after initial gas sales, which commenced in September 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 uncertainty in estimating the characteristics of our property; 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 uncertainty of our industry as a whole; the volatility of natural gas prices and its potential adverse effect on our financial condition and operations; the difficulty in executing our business strategy if we cannot manage our future growth effectively, our inability to obtain the commercial contracts necessary to facilitate direct delivery of our natural gas production on commercially reasonable terms; 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 uncertainties in estimating existing quantities of proved and possible reserves; our dependence on certain members of management and our technical team; our limited control over properties operated by others or through joint ventures; the inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results; the concentration of a majority of our assets and operations in the Beetaloo, making us susceptible to region-specific risks; our inability to make accretive acquisitions or successfully integrate acquired businesses or assets; operating hazards that could result in liabilities for which we may not have adequate insurance coverage; the risks inherent to the exploration and production of natural gas; delays and cost overruns resulting from the long term development schedule of natural gas projects; uncertainties arising from the identified drilling locations being scheduled out over several years, that could materially alter the occurrence or timing of the drilling; the risk that 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; 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; our ability to attract a third-party partner and secure permitting to develop an additional LNG export terminal on Australia's northern coast; financial crises; events outside our control, such as epidemics, geopolitical instability, terrorist attacks; cybersecurity threats and disruptions, as well as any compromised information or systems resulting from such disruptions; operational, compliance, cybersecurity, and reputational risks associated with the incorporation of artificial intelligence technologies into our processes; loss of or compromise to our information and computer systems; potential legal proceedings that result in liabilities; risks related to corporate social responsibility and our estimates thereof; 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 net zero goals, which may increase our production costs; attention to sustainability and ESG matters and environmental conservation measures that could adversely impact our business operations; restrictions and delays that may result from federal and local initiatives relating to hydraulic fracturing; reduced demand for the natural gas we produce or increased compliance costs due primarily to risks related to climate change; limitations on our ability to pursue business strategies if we incur costs related to a failure to comply with environmental, health or safety regulations; potential future regulation by the Northern Territory of Australia; unanticipated water and waste disposal costs as a result of increased water-related laws and regulations; restrictions on drilling, completion, production or related activities intended to protect certain species of wildlife; increased costs of compliance with evolving data privacy laws; risks related to our corporate structure as a holding company; the inability to achieve some or all of the benefits that we expect to achieve from the Corporate Reorganization; the requirements of being a public company may strain our resources, and we may be unable to comply with these requirements in a timely manner; changes in foreign currency exchange rates may impact our business, results of operations, or financial conditions; transactions with affiliates may not always be in the best interests of our stockholders; our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposal; 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; a lack of positive cash flow until at least 2028; preferred stock which could be issued in the future adversely affecting the voting power of common stock; a material weakness in our financial reporting may cause us to fail to timely and accurately report our financial results or result in a material misstatement of our financial statements; our status as an emerging growth company means that 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; the loss of our emerging growth company status subjecting us to more legal and compliance costs; Section 107 of the JOBS Act granting us an extended transition period, rendering our financial statements not comparable to those of other public companies; capital market differences between the U.S. and Australia may negatively impact the trading prices of our CDIs and common stock, and may limit our ability to act; our ability to raise capital may be significantly limited by listing rules of the ASX; an investor's 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; being subject to the listing rules of the ASX may strain our resources, divert management's attention, and affect our ability to manage the business or raise additional capital; arbitrage activities; changes in accounting standards issued by the Financial Accounting Standards Board ("FASB") or other standard-setting bodies; and the other risk factors discussed in 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 report or other locations, such as the Company's corporate website, regarding sustainability or ESG matters, are informed by various 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 or other regulatory purposes, even if the Company uses the word "material" or "materiality" in such discussions, and materiality as used in the context of sustainability, ESG and climate-related disclosures may differ from the materiality standards applied under other reporting regimes. Sustainability and 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. Statements regarding the Company's sustainability, ESG and emissions targets, goals and aspirations, including its net zero equity Scope 1 and 2 goals, are aspirational and are not guidance, and actual performance against them may be affected by a variety of risks and uncertainties, including the pace and direction of the global energy transition, the availability, cost and integrity of carbon offsets, evolving GHG accounting and measurement methodologies, technological developments, regulatory and joint venture approvals and third-party activities, many of which are beyond the Company's control. For example, the Company's disclosures may change due to revisions in framework requirements, availability of information, changes in its business or applicable governmental rules and 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 a limited operating history and uncertain future performance;
- Our business plan requires substantial additional capital;
- Our ability to deliver natural gas to target markets depends on construction of additional pipeline capacity;
- Our drilling areas may not yield natural gas in commercial quantities or quality;
- We face substantial uncertainty in estimating the characteristics of our property;
- Drilling is speculative and may not result in discoveries or additions to production or reserves;
- We face challenges importing U.S. practices and technology to the Northern Territory and attracting a qualified workforce;
- Timely access to appropriate equipment and infrastructure is critical to our market access and business plan;
- Drilling, completions, workover and hydraulic fracturing operations present operational risks;
- Our industry is subject to uncertainties, including volatile natural gas prices;
- We may be unable to manage future growth and obtain the midstream contracts needed to execute our strategy;
- Midstream projects are subject to construction delays and cost overruns;
- Our assessments of the Beetaloo and estimates of reserves may be materially inaccurate;
- We are dependent on certain members of our management and technical team;
- We have limited control over properties and investments operated by others or through joint ventures;
- Third-party failures to meet contractual obligations may adversely affect our financial results;
- Our concentration in the Beetaloo exposes us to risks associated with operating in one geographic area;
- We may be unable to make accretive acquisitions or successfully integrate acquired businesses or assets;
- Our business is subject to operating hazards that could result in substantial losses or liabilities inherent to the exploration and production of natural gas for which we may not have adequate insurance coverage;
- We are subject to risks inherent to natural gas exploration and production;
- Our drilling locations are scheduled over years, such that uncertainties, including availability and cost of rigs, equipment, supplies, personnel and natural gas field services, could materially alter the cost of their drilling;
- Natural gas project development is subject to delays and cost overruns;
- 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;
- Our business plan contemplates developing a new LNG export terminal on the northern coast of Australia. Our ability to develop a facility is dependent on securing a third-party partner and the necessary permits;
- A financial crisis or deterioration in general economic, business or industry conditions could adversely affect our results;
- Events outside our control, including epidemics, geopolitical instability, terrorism and security threats, could adversely affect our business;
- Our business could be negatively affected by security threats and disruptions, including electronic, cybersecurity or physical security threats and other disruptions;
- Artificial intelligence technologies may present business, operational, compliance, cybersecurity and reputational risks;
- Loss of or compromise to our information and computer systems could adversely affect our business;
- We may be involved in legal proceedings that could result in substantial liabilities; and
- We are subject to risks related to corporate social responsibility.

Risks Related to Environmental, Legal Compliance and Regulatory Matters

- Complex laws and regulations could increase our operating costs or expose us to significant liabilities;
- Community opposition could result in significant costs and delays and impede required government approvals;
- Native title and heritage issues could lead to legal disputes, operational disruptions and reputational damage;
- Net zero requirements and goals may increase our production costs and may be difficult to meet;
- Sustainability, ESG and environmental conservation measures may adversely affect our business;
- Hydraulic fracturing initiatives could increase costs, restrict operations or delay natural gas well completion;
- Climate change risks could increase costs, limit production areas and reduce demand for our natural gas;
- Failure to comply with environmental, health and safety laws could limit our business strategies and result in costs and liabilities;

- Future gathering systems and processing facilities will be subject to Northern Territory regulation;
- We may face unanticipated water and other waste disposal costs;
- Wildlife protection restrictions could limit drilling, completion, production or related activities; and
- Our business is subject to complex and evolving laws and regulations regarding privacy, data security and the processing of personal information.

Risks Related to our Corporate Structure

- We are a holding company dependent on distributions from TR Ltd. to pay taxes and corporate expenses; and
- We may be unable to achieve some or all of the benefits expected from the Corporate Reorganization;

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, and the requirements of the SOX, may strain our resources 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 conditions;
- 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;
- Our certificate of incorporation and bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or proposals, which may adversely affect the market price of our CDIs and common stock;
- Our exclusive Delaware forum provision may limit stockholders' ability to obtain a favorable judicial forum;
- We do not expect positive cash flow until at least 2028 or to pay dividends in the foreseeable future;
- Future issuances of preferred stock could adversely affect voting power or value of CDIs and 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;
- Our emerging growth company status exempts us from certain reporting requirements applicable to other public companies;
- Loss of our emerging growth company status may increase our legal and compliance costs;
- Our extended transition period pursuant to Section 107 of the JOBS Act may make our financial statements not comparable to those of other public companies;
- Trading in our CDIs may have a material adverse effect on the trading price of our common stock on the NYSE;
- The differences between the capital markets in Australia and the United States may negatively affect the trading prices of our CDIs and common stock, and limit our ability to take actions performed by U.S. companies;
- 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;
- An investor may have limited ability to bring an action against us or our directors and officers, because our directors reside in and we conduct a majority of our operations in Australia;
- ASX listing rules may strain our resources, divert management's attention and affect our ability to manage our business or raise additional capital;
- The market price of our common stock may be adversely affected by arbitrage activities; and
- Changes in accounting standards may adversely affect our financial statements.

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 reflects 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.

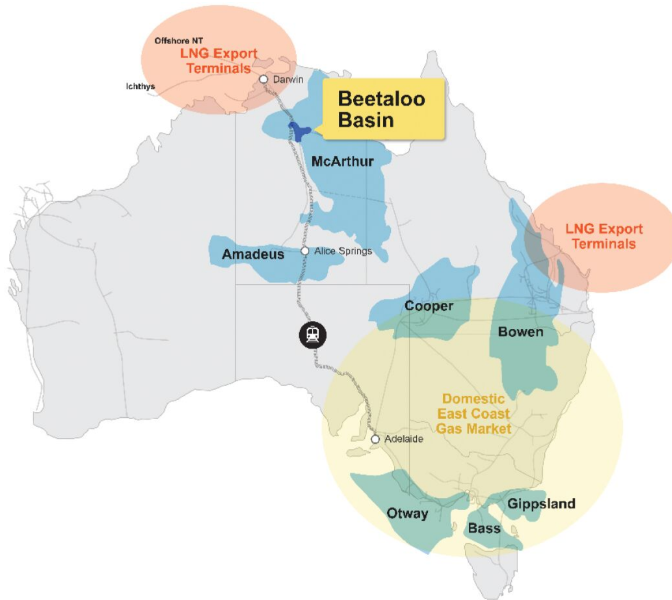
The terms “we,” “us,” “our” and the “Company,” as used herein and unless otherwise stated or indicated by context, refer to TR Ltd. and its subsidiaries prior to the Corporate Reorganization and to Tamboran and its subsidiaries after the Corporate Reorganization.

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. Through its subsidiaries, Tamboran holds approximately 2.8 million net prospective acres and is the largest acreage holder in the Beetaloo Basin. 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 Basin with net zero equity Scope 1 and 2 emissions.

The Beetaloo Basin

The Beetaloo Basin, an area of approximately seven million acres (10,800 square miles), is believed to contain significant quantities of unconventional natural gas resources. The Beetaloo Basin 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 Federal Government's current policy is to target net zero carbon emissions economy-wide by 2050. The Australian government's 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 (the "Safeguard Mechanism"). The Australian government has announced a review of the Safeguard Mechanism, which is due to commence in the second half of calendar year 2026 and conclude during calendar year 2027. We have set a target to exceed these current 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 net zero equity Scope 1 and 2 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. 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 Basin 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

Tamboran's business plan to develop the Beetaloo Basin consists of three phases, addressing structural supply shortages within three markets. The focus of the first phase is on the transition from exploration activities to commercialization by delivering the Shenandoah South Pilot Project. The project aims to supply initial gas sales into the local Northern Territory gas market, delivering early revenue to Tamboran and royalties to key stakeholders, such as the Northern Territory Government and Native Title Holders. Tamboran has drilled and completed the initial five wells and achieved mechanical completion of the Sturt Plateau Compression Facility ("SPCF") in July 2026.

During fiscal year 2026, Tamboran progressed the first phase towards the commercialization delivering on key milestones, including:

- taking final investment decision on the Shenandoah South Pilot Project,
- executing a binding, take or pay Gas Sales Agreement with the NT Government,
- drilling SS2-1H, -3H and -5H with ~10,000-foot horizontal sections,
- safely executing a stimulation program on SS2-1H and commencing a stimulation plan for SS2-3H, SS2-4H and SS2-5H,
- completing record Beetaloo Basin IP30, IP60 and IP90 flow rate tests on SS2-2H ST1,
- achieving record IP20 flow rates from the SS2-1H well, and
- receiving Native Title Holder consent and Northern Territory Government approval to sell gas under the Beneficial Use of Gas ("BUG") legislation, which allows Tamboran to sell gas under an exploration permit during the appraisal period.

Over the course of fiscal year 2027, Tamboran plans to progress our development activities in the Shenandoah South Pilot Project, which successfully delivered first commercial sales in September 2026, including:

- the drilling and tie-in of the three additional Shenandoah South wells (SS1-2H, SS1-4H and SS1-6H),
- completing construction activities, commissioning and practical completion of the SPCF.

Gas sales are expected to ramp to the full 40 TJ/d (approximately 41 MMcf/d) (gross) plateau rates in accordance with the Northern Territory Government's nominations, subject to well performance and final SPCF commissioning activities.

During fiscal year 2026, APA Group (ASX: APA), Australia's largest gas infrastructure company, successfully completed construction of the 12-inch diameter Sturt Plateau Pipeline ("SPP"). The 23-mile pipeline allows for gas to flow from the SPCF to the Amadeus Gas Pipeline ("AGP"). APA Group achieved practical completion on the SPP in July 2026 and commenced receiving sales gas and charging the transportation toll in September 2026.

The Beetaloo Joint Venture continues to evaluate options for a potential expansion of the SPCF to up to 100 TJ/d, with an investment decision planned for mid-2027. Tamboran is evaluating pipeline availability to access additional markets within the Northern Territory and Mount Isa networks.

The second development phase involves constructing a new high capacity pipeline to access the Australian East Coast domestic gas market and ullage in the existing East Coast LNG export facilities in Gladstone. APA Group is evaluating the opportunity to construct an approximately 1,000-mile pipeline connecting the Beetaloo to the East Coast gas grid network.

Australia's East Coast gas market currently has ~5 Bcf/d of demand, including ~1.3 Bcf/d domestic and ~3.6 Bcf/d LNG export capacity. A gas shortfall is forecast on the East Coast in the late-2020s, providing a near-term opportunity for Beetaloo Basin gas to fill an increasing supply gap. Tamboran has secured 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.

The third phase of development aims to supply natural gas for export through the existing LNG plants in the Middle Arm Precinct ("MAP") near Darwin and Tamboran's proposed Northern Territory LNG export facility ("NTLNG") to South and East Asian markets. Pre-FEED of the NTLNG project was completed in mid-2025 with Bechtel, the world's leading LNG engineering, procurement and construction ("EPC") contractor, assessing the potential first phase to consist of two 6 million tons of LNG per annum LNG trains, each train consuming approximately 1 Bcf/d of gas from the Beetaloo Basin.

Tamboran is also assessing opportunities to provide gas to existing LNG facilities. In consideration of the 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 an interim agreement, with two one-year extension options to progress FEED studies with respect to NTLNG.

The MAP, 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 MAP 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. Tamboran has secured non-binding memoranda of understanding (MOUs) with bp and Shell for 20-year LNG purchase contracts. Tamboran is evaluating strategic partnerships for the financing and development of these and other infrastructure projects.

Tamboran plans to deliver the proposed development plan with a continuous focus on reducing costs while increasing production efficiencies. The strategy includes importing U.S. unconventional drilling and completion techniques, best-practices and technology, together with the right personnel, which is expected to reduce the incremental cost to drill and complete future wells. Tamboran has contracted Helmerich & Payne, Inc. (NYSE: HP) for one H&P FlexRig® with a 10-year option to contract for up to four additional rigs.

Tamboran has also 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). Tamboran and Liberty Energy recently signed an MOU in September 2026 setting out the intent to extend the hydraulic fracture stimulation and wireline services agreement covering Tamboran's operations in the Beetaloo Basin. The MOU further contemplates priority access for Tamboran to a broader set of Liberty Energy capabilities as they are introduced to Australia, including gas processing and conditioning and remote gas-fired power generation through Liberty Power Innovations, PropX sand slurry delivery and collaboration on the development of local proppant supply.

Investment Highlights

Key strengths to support Tamboran’s successful execution of the business strategy, include:

- **Proven Team**. Proven Board and Management with operational and commercialization experience to unlock large-scale shale developments.

- **Basin-scale acreage position**. Largest Beetaloo Basin acreage holder, owning majority of the basin’s prospective area with 2.8 million net prospective acres and 3 – 4 stacked benches across two key depocenters.

- **Partners accelerating lessons**. Tamboran has brought in strategic partnerships (all equity holders) with Helmerich & Payne (NYSE: HP), Liberty Energy (NYSE: LBRT) and Baker Hughes to accelerate incorporation of lessons from the U.S. shale industry.

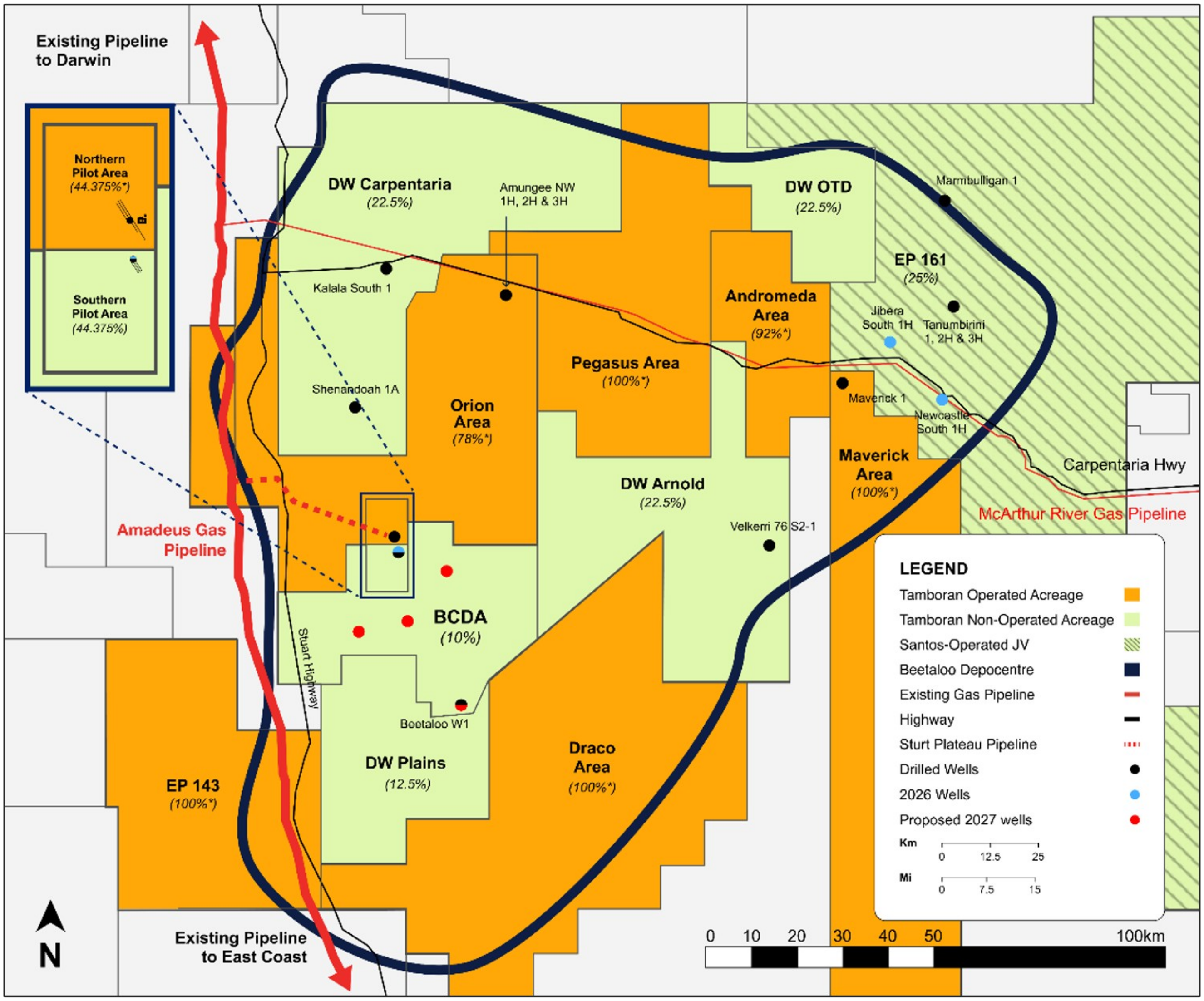
- **Most experienced operator**. Tamboran’s operations team has been involved in the Beetaloo Basin for over a decade, operating nine horizontal wells across the basin, the most by any operator.

- **Moving to producer**. Transition to producer with first gas sales achieved in September 2026; 40 TJ/d (gross) from Pilot Project contracted to the Northern Territory Government at fixed price, CPI escalated.

- **Multiple gas markets**. Three highly attractive markets trading at attractive premiums to U.S. Henry Hub price and potential future exposure to international LNG.

Our Assets and Operations

Tamboran holds interests across various exploration permits (EPs) in the Beetaloo Basin, which have been divided into sub-blocks following a Checkerboard process (as defined below) with Daly Waters Energy, LP in 2025, and one production license, located in Hungary (“*Makó-árok I.*”, hereinafter: “Makó” or the “Makó License”). See “—Title to Properties” for further information. The table below highlights Tamboran’s working interest across Beetaloo Basin assets.


Existing Pipeline to Darwin
Northern Pilot Area
(44.375%*)
Southern Pilot Area
(44.375%)
DW Carpentaria
(22.5%)
Amungee NW 1H, 2H & 3H
Kalala South 1
Shenandoah 1A
Orion Area
(78%*)
Pegasus Area
(100%*)
Andromeda Area
(92%*)
DW OTD
(22.5%)
EP 161
(25%)
Marmbulligan 1
Jibera South 1H
Tanumbirini 1, 2H & 3H
Maverick 1
Newcastle South 1H
Carpentaria Hwy
McArthur River Gas Pipeline
Maverick Area
(100%*)
DW Arnold
(22.5%)
Velkerri 76 S2-1
Amadeus Gas Pipeline
BCDA
(10%)
Stuart Highway
Beetaloo W1
DW Plains
(12.5%)
Draco Area
(100%*)
EP 143
(100%*)
Existing Pipeline to East Coast
N
LEGEND
Tamboran Operated Acreage
Tamboran Non-Operated Acreage
Santos-Operated JV
Beetaloo Depocentre
Existing Gas Pipeline
Highway
Sturt Plateau Pipeline
Drilled Wells
2026 Wells
Proposed 2027 wells
Km 0 12.5 25
Mi 0 7.5 15
0 10 20 30 40 50 100km

The table below represents Tamboran's net prospective acres once the Checkerboard process is completed and, (excluding EP 161, EP 143 and EP 136) are subject to the completion of the minority shareholder compulsory acquisition of Falcon Australia which follows the completion of the broader transaction with Falcon in May 2026.

Working interests also include the impact of:

- the Acreage Sale to Daly Waters Energy, LP, announced in May 2025 and subject to completion of certain conditions precedent,
- the Acreage Realignment Agreement with Daly Waters Energy, LP, announced in November 2025, and
- the farmout to Daly Waters Energy, LP, announced in March 2026.

Permits	Gross Prospective Acres	Interest	Net Prospective Acres
Northern Pilot Area	20,239	44.38%*	8,982
Southern Pilot Area	20,230	44.38 %	8,978
Orion Block	493,229	78.00%*	384,719
Beetaloo Central Development Area (BCDA)	316,131	10.00 %	31,613
Andromeda Block	218,176	92.00%*	200,722
Pegasus Block	536,669	100.00%*	536,669
Draco Block	914,839	100.00%*	914,839
DW OTD Area	813,460	22.50 %	183,029
DW Plains Area	281,633	12.50 %	35,204
DW Arnold Area	525,740	22.50 %	118,292
DW Carpentaria Area	202,931	22.50 %	45,659
EP 161	512,000	25.00 %	128,000
Maverick Block	207,000	100.00%*	207,000
Total	**5,062,277**		**2,803,706**

** Denotes operated permit following the completion of the Checkerboard.*

Tamboran has participated in eight wells with the ninth well currently drilling within the Shenandoah South Pilot Project since 2024. A table of the wells references the updated naming convention for wells in the region and the current well status.

New Name	Previous Name	Status
SS-1H	SS-1H	90-day flow test over 500 meters
SS1-2H	SS-9H	Currently drilling
SS1-4H	SS-8H	Drilled and awaiting completion
SS1-6H	SS-7H	Drilled and awaiting completion
SS2-1H	SS-6H	20-day flow test, tied-in to SPCF
SS2-2H ST1	SS-2H ST1	90-day flow test, tied into SPCF
SS2-3H	SS-5H	Drilled and completed, tied into SPCF
SS2-4H	SS-3H	Drilled and completed, tied into SPCF
SS2-5H	SS-4H	Drilled and completed, tied into SPCF

In conjunction with the Checkerboard (as defined below), Tamboran and DWE entered into an agreement whereby DWE would acquire a non-operating and non-controlling interest across 100,000 acres within two areas of Tamboran's post-checkerboard acreage position for a consideration of $15 million. See "*—Agreements Relating to the Development of our Assets — Asset Sale Agreement*".

Royalty Owners

We are 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). Further private royalties are in place over the permits for individual amounts from 0.1% to 5.5% which accumulate to between 2% and 11% depending on the commercial arrangements that have been entered into with the private royalty holders. 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 2026 Proxy Statement for further information.

Mr. Bryan Sheffield holds a 2.3% overriding royalty interest ("ORRI") through Daly Waters Royalty over all of our Beetaloo assets, plus an additional 0.3% over the Beetaloo assets acquired through Falcon. Mr. Bryan Sheffield also holds an additional 0.45% royalty over the Beetaloo assets acquired through Falcon through a holding company.

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.

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 the Company. The ORRI extends to all extensions or renewals of each of the 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.

Tamboran B2 Pty Ltd (formerly Origin Energy B2 Pty Ltd) granted a 0.775% ORRI in favor of the Bayless Group, comprising Tom Dugan Family Limited Partnership, Territory Oil & Gas LLC and Malcolm John Gerrard over EPs 76, 98 and 117.

Agreements Relating to the Development of our Assets

Capitalized terms used but not defined in this section or elsewhere in this report have the meanings ascribed to them in the applicable agreement.

TB1 A&R JVSA

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 Mr. Bryan Sheffield. TB1 in turn wholly owns TB1 Operator.

On May 12, 2025, we entered into the TB1 A&R JVSA. The following summary of the TB1 A&R JVSA does not purport to be complete and is qualified in its entirety by reference to the full text of the TB1 A&R JVSA, a copy of which is attached as Exhibit 10.29 to this report.

Under the terms of the TB1 A&R JVSA, 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 (Eric Dyer 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. 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 retention and production license applications.

Special Approvals

Under the TB1 A&R JVSA, 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 A$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 or 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 A&R JVSA;
- 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.

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-contributing party bearing interest at a rate 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 a 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 TB1 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 TB1 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. The right to convert a defaulting party's funding shortfall into equity is subject to the procedures described in the TB1 A&R JVSA.

Conversion to Checkerboard

Checkerboard Strategy means an approach to dealing with EPs 76, 98 and 117 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 Checkerboard Strategy and the Technical Committee must, acting in good faith, consider the best approach to implementing the Checkerboard Strategy.

The Checkerboard Strategy (“Checkerboard”) was structured in two tranches.

In Tranche 1, Tamboran and Daly Waters must apply for retention licenses for both the North and South First Strategic Development Areas (“FSDAs”). Following various agreed extensions, applications were submitted in March 2026 over North FSDA, South FSDA, Orion (formerly referred to as Dev A++) and Beetaloo Central Development Area (BCDA) and the retention licenses are expected to be awarded in late 2026. On March 23, 2026, Tamboran and Daly Waters executed the Stage 1 Checkerboard Sale and Purchase Deed covering this acreage, with completion subject to a number of conditions expected to be completed later this year. The North FSDA will remain with TB1 with Tamboran remaining as Operator. The South FSDA will be sold to related parties, split equally (38.75% each) between Tamboran and DWE, with DWE (or its nominee) acting as Operator. The Orion and BCDA acreage will also be sold to related parties, with Tamboran remaining as operator of Orion and DWE taking over operatorship of BCDA.

Tranche 2 covers the remaining Checkerboard permit areas. On March 25, 2026, Tamboran and Daly Waters executed the Stage 2 Checkerboard Sale and Purchase Deed covering this acreage. The timeline for submission of further retention licenses has not been agreed yet, and the joint venture will continue to develop the acreage in accordance with its commitment obligations.

In conjunction with the Checkerboard, the Company and DWE entered into an Asset Sale Agreement. See “Asset Sale Agreement”.

Gas Marketing and Midstream Rights

The TB1 A&R JVSA grants DWE an option to back-in for 50% of any new gas sale agreement (“GSA”) covering the first 0.5 Bcf/d of sales entered into by Tamboran or its affiliates until 24 months after all Checkerboard Blocks are licensed.

DWE (or its nominee) is granted a 50% option, on identical commercial terms, to participate in any Beetaloo-related infrastructure project (pipelines, processing, sand, water, etc.) undertaken by Tamboran or its affiliates, exercisable within 90 days of receiving detailed commercial terms.

TB1’s right-of-first-refusal over expansions of SPP and the SPCF is prioritized for the FSDAs gas; if only one shareholder supports an expansion, that shareholder may utilize 100% of the added capacity.

Commitment Wells; Development Obligations

The TB1 A&R JVSA requires six horizontal “Commitment Wells” (minimum 7,500 ft laterals; ≥45 stages) to be drilled, completed, and tied-in over three consecutive work-program years (2025–2027). DWE will select all Commitment Well locations, with at least four wells required in the North FSDA. This obligation has been met with the drilling of three wells in the North FSDA in 2025 and the drilling of three wells in the South FSDA in 2026.

Other

Where retention licenses in the North FSDA and/or the South FSDA remain 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 prior to December 31, 2026.

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 has 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 A&R JVSA 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 A&R JVSA (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 also a party to a joint operating agreement with Falcon Australia (the "Beetaloo JOA"). The Beetaloo JOA establishes the respective rights and obligations of the TB1 Operator and Falcon Australia in connection with EPs 76, 98, and 117. The TB1 Operator is designated as the operator under the Beetaloo JOA. Prior to the closing of the Falcon Acquisition, the TB1 Operator held a 77.5% working interest and Falcon Australia held a 22.5% non-operated working interest in the Beetaloo JOA. On May 28, 2026, Tamboran acquired approximately 98.1% of the issued and outstanding equity interests of Falcon Australia. On July 23, 2026, Tamboran completed the acquisition of FOGA minority stock held by sophisticated investors in exchange for 60,259 shares of Tamboran common stock.

Asset Sale Agreement

On May 12, 2025, TR West, as seller, and the Company, as seller guarantor, and DWE entered into a binding agreement whereby DWE would acquire a non-operating and non-controlling interest across 100,000 acres within two areas of Tamboran's post-checkerboard acreage position for consideration of $15 million. The transaction is subject to certain conditions precedent including, but not limited to, DWE obtaining approval from the Formentera Australia Fund, LP's Limited Partner Advisory Committee, Tamboran shareholder approval and regulatory approvals ("Original ASA").

On March 20, 2026, the parties entered into a Deed of Addendum to the Asset Sale Agreement ("ASA Addendum"), which among other things, provides that Elliott Energy I Pty Ltd will only acquire a beneficial interest in the Dev A++ Area to facilitate the application for a retention license over the Phase 2 Development Area, which will incorporate the Dev A++ Area together with approximately 100,000 acres of additional acreage. The ASA Addendum also deletes the escrow provisions contained in the Original ASA and extends the Dev A++ End Date (as defined in the Original ASA) to December 31, 2026 and the C10 End Date (as defined in the Original ASA) to December 31, 2027 (or such other dates as the parties may agree in writing).

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 proportionate interest in the underlying permit. 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 $6.0 million through March 2027 based on minimum work requirements. Tamboran has approved a CY2026 budget including a two well program and hydraulic fracturing long lead items for a commitment of approximately A$26 million.

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 SS-1H 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.

APA Group Agreements

Tamboran entered into agreements with APA Group whereby APA will build, own and operate the 23-mile (37 kilometer) 12-inch diameter Sturt Plateau Pipeline ("SPP") for the Shenandoah South Pilot Project. The SPP will connect the SPCF to the existing APA-owned AGP, the delivery point for gas volumes under the Gas Sales Agreement with the Northern Territory Government ("NTGGSA").

Tamboran and DWE have contracted all foundation capacity on the SPP from the commencement of operations until at least 2041, which reflects the term of the NTGGSA and have competitive access and pricing rights to contract capacity following completion of the initial term. Practical completion on the SPP occurred in July 2026 and sales volumes of gas were delivered into the pipeline in early September 2026 marking first volumes delivered from the Beetaloo Basin to the Northern Territory gas market.

Tamboran also entered into an Early Development Agreement with APA Group for a pipeline from the Beetaloo to the East Coast Pipeline (the "BEC EDA") to progress 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 BEC EDA, APA Group has agreed to continue evaluation of the proposed pipeline with early works expenditure of up to A$5 million on the basis that we continue to progress and achieve certain agreed milestone 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 BEC EDA is a preliminary agreement related to the development of the BEC Pipeline Project, 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 for the potential supply of gas sourced from EPs 98, 76, or 117. The supply and purchase obligations under the Origin GSA are subject to conditions precedent. These include the TB1 Operator making a positive final investment decision on the development of the permits, which was required to be satisfied by January 1, 2026. That condition precedent was not satisfied by that date, and Origin Retail may terminate the Origin GSA, and the TB1 Operator may terminate it on or after January 1, 2027, if that condition precedent remains unsatisfied on that date. Notwithstanding, certain negotiation rights in favor of Origin Retail remain and will survive upon termination and come into effect for the further occasion where the TB1 Operator or any of its related bodies corporate proposes to enter into a gas sales agreement with a third party with a firm maximum daily quantity of at least 200 TJ/d (~206 MMcf/d), or the annual equivalent.

NT Government Gas Sales Agreement

On April 23, 2024, the Beetaloo Joint Venture signed the NTGGSA to supply the NT Government with 40 TJ/d (equivalent to ~41 MMcf/d gross) from the Shenandoah South Pilot Project for an initial term that expires at the end of 2034, with the first gas supply occurring in September 2026. The Buyer has an option to extend the NTGGSA for a further 6.5 years through to mid-2041.

The NTGGSA includes conditions precedent that require satisfaction for the agreement to become binding. Specifically, the NTGGSA is conditional on the Beetaloo Joint Venture entering into a binding gas transportation agreement with APA Group on the SPP, a binding gas processing agreement for the SPCF, reaching a final investment decision on the Shenandoah South Pilot Project, and receiving key regulatory and stakeholder approvals, all of which have now occurred. Once the NTGGSA becomes binding, the Beetaloo Joint Venture is required to deliver the daily quantity of gas available each day unless excused under the contract as part of permitted interruptions or Force Majeure. If there is an unexcused supply shortfall, the Beetaloo Joint Venture may be liable to pay shortfall liquidated damages.

Volumes from the Shenandoah South Pilot Project are expected to ramp up to the full 40 terajoules per day (TJ/d) over the remainder of 2026. During this commissioning period, Tamboran and DWE will receive a discounted price for the gas, reflecting the interruptible nature of supply during the commissioning period.

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 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, 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, 2026, we employed 45 people full-time and two part-time people. 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 a high priority for us, 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 covers spill response and reporting and take steps to 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 include 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 Meridian and Korn Ferry Compensation Consulting firms, which are leading independent global compensation consultants.

Sustainability and ESG

Sustainability is a central component of our 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 environment. To highlight the importance of Sustainability and ESG, the Company has a Six-Pillar Sustainability Plan, which includes: (i) Health and Safety: Putting the health and safety of our people first; (ii) Climate Change: Responsibly delivering a low GHG intensity natural gas project; (iii) Environment: Protecting the local environments in which we operate; (iv) Community: Working closely with, and strengthening the local communities; (v) People: Being a preferred employer and partner of choice; and (vi) Economic Sustainability: Generating economic growth and value for investors, employees, customers and communities. The Federal Safeguard Mechanism (legislation.gov.au) provides regulations that shale gas facilities will have a "zero greenhouse gas baseline" meaning they must have Net Zero Scope 1 emissions by law once facilities enter the Safeguard Mechanism. The Australian government has announced a review of the Safeguard Mechanism, which is due to commence in the second half of calendar year 2026 and conclude during calendar year 2027.

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, which are subject to change from time to time. 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, has been restricted. Our operations could be adversely affected to the extent laws are enacted or other governmental action is taken that prohibits or restricts onshore 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 and 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 mandate 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 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 Lands, Planning and Environment website *www.environment.nt.gov.au/onshore-gas/environment-management-plan/approved-emps.* The EMPs describe how our regulated activities might impact the environment in which the activity occurs and establish 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 EMPs, 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 GHG 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 tonnes of CO_2-e per year and requires that all emissions from the Beetaloo be offset with Australian Carbon Credit Units or Safeguard Mechanism Credits once the 100,000 tonnes 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 tonnes CO_2-e trigger in a given fiscal year, all Scope 1 emissions in that fiscal year are required to be offset. The Australian Federal Government has established an A$82.68 carbon offset price cap for fiscal year 2026. The offset price cap increases by CPI plus 2% each year. The Australian government has announced a review of the Safeguard Mechanism, which is due to commence in the second half of calendar year 2026 and conclude during calendar year 2027. The review will consider key settings including the baseline decline rate beyond 2030 and the threshold for covered facilities. 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 with 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 Environment Protection Authority ("NT EPA") for assessment under the *Environment 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 NT EPA, and require Tamboran to obtain approvals under the Environment Protection Act (an "Environmental Approval") to conduct the activity. Civil proceedings could be brought by any person who is affected by an alleged act or omission that contravenes or may contravene the Environment Protection Act. Contraventions of an Environmental Approval can attract significant monetary penalties. Contravention can also result in revocation of the Environmental Approval.

The *Environment Protection Act* was amended 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). A petroleum activity is an activity for which an EP, retention license or production license is required. The chain of responsibility amendment permits a compliance notice to be issued to a related person with a relevant connection to a high risk entity conducting a petroleum activity. For corporations, contraventions of a relevant notice can attract significant monetary fines, with the exact amount 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 an 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 Australian government passed legislation in December 2025 to reform the EPBC Act, with the majority of the reformed provisions to commence by the end of 2026. The reforms include new application and decision making processes, including a new information requirement in relation to Scope 1 and 2 emissions, the making of National Environmental Standards (NES), and new decision making rules relating to 'unacceptable impacts', requirements for projects to be consistent with NES and to deliver 'net gain', and establishing an independent regulator (National Environment Protection Authority), with enhanced compliance powers and increased penalties for non-compliance.

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 (450 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. Existing WEL allocations may be increased and new WELs acquired to cover the future proposed exploration and development 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 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 Environment 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* 2011 (NT) ("WHS") 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 (NT)*, 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 AAPA 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 locations 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 AAPA 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 directional 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 is the most relevant provision of the Native Title Act to Tamboran's operations. The Right to Negotiate process was applied to the grant of Tamboran's exploration 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 Northern 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.

The 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 or that such coverage will continue to be available, or available on acceptable terms or at acceptable rates. 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 NT 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. The Makó interest is set out below. See "—Hungarian Mining Plot" for further information.

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 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 an agreement is reached, which often takes between three and five 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 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.

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.

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.

Hungarian Mining Plot

Makó-árok I. – szénhidrogén (non-conventional) mining plot ("Makó License"), which was established by resolution of the Szolnok Mining Inspectorate on May 21, 2007, is situated in Hungary, measuring approximately 1,000 km2, and is owned 100% by TXM Olaj- és Gázkutató Korlátolt Felelősségű Társaság ("TXM" or Falcon Hungary), which is a 100% subsidiary of Tamboran Resources Investments Holding Corporation. Seven deep wells have been drilled on the license with the last well drilled in 2009. Since then, the license has been put on care and maintenance with the exception of the drilling of two shallow wells in 2013/14 (both of these wells were plugged and abandoned).

Under the Hungarian Mining Act (Act XLVIII of 1993) (the "Mining Act"), hydrocarbons (as mineral resources) are owned by the State in their natural occurrence. Ownership of hydrocarbons extracted by a mining entrepreneur passes to the mining entrepreneur upon extraction, against payment of the mining royalty (bányajáradék) in accordance with the applicable statutory rates (ownership of the surface land remains separate; the Hungarian State has a statutory pre-emption right upon any transfer of real property affected by hydrocarbon mining rights, while ownership of mining authority-approved special structures vests in the builder unless otherwise agreed). Hydrocarbon mining activities, in the case of the Makó License are carried out on the basis of an authority permit (since 2010 hydrocarbon mining licenses are exclusively based on a concession agreement, but the Makó License wass established before the concession regime was introduced). The exclusive right to explore for and extract hydrocarbons may only be exercised on the basis of a duly established mining plot (in Hungarian bányatelek)— a designated parcel of surface and subsurface reserved for hydrocarbon extraction purposes.

Following expiry of a mandatory suspension Technical Operating Plan ("TOP") between July 2025 and July 2026, the Makó License is currently subject to a specific one-year production TOP approved by the mining authority with a resolution dated July 24, 2026. There is an amendment in progress in which TXM, as applicant indicated that the planned natural gas production during such period totals 225,500m³ while no crude oil production is planned.

As a condition of TOP approval, the mining plot holder must fulfill its ongoing site restoration obligations and maintain an adequate reclamation financial security lodged with the respective mining authority. In respect of the Makó-árok I. mining plot, TXM has deposited HUF 780,322,901 or approximately $2.5 million at the mining authority as security.

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, 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 expiration 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 specific minimum work obligations. The minimum work obligations in respect of the EPs that need to be completed in the near future include:

- EP 76: that between May 31, 2025 and May 30, 2027 the following work is completed with an estimated expenditure of A$500,000: (a) undertake planning, design, contracting and operational readiness for drilling and stimulation in Permit Year 5;
- EP 98: that between May 31, 2025 and May 30, 2027 the following work is completed with an estimated expenditure of A$43,500,000: (a) drill, complete and suspend one horizontal exploration well; (b) drill and hydraulic fracture stimulate two horizontal exploration/appraisal wells; (c) formation evaluation of acquired data; (d) integrate seismic and well data to update prospective play mapping and resource estimation; and (e) undertake planning, design, contracting, and operational readiness for drilling and stimulation in Permit Year 5;
- EP 117: that between May 31, 2025 and May 30, 2027 the following work is completed with an estimated expenditure of A$2,500,000: (a) undertake 3D seismic surveys; (b) integrate seismic and well data to remodel: structural models, source rock maturity, prospectivity play mapping and resource estimation; and (c) undertake planning, design, contracting, and operational readiness for drilling and stimulation in Permit Year 5;
- EP 136: that between July 24, 2025 and July 23, 2027 the following work is completed with an estimated expenditure of A$20,500,000: (a) drill and multistage fracture stimulate one horizontal exploration/test well targeting the Velkerri or other formation deemed prospective; (b) formation evaluation of acquired data including petrophysical interpretation and stimulation design; (c) integrate new geological and technical data and information into current exploration models; and (d) update assessment of petroleum resource potential;
- EP 143: that between January 1, 2026 and December 31, 2027 the following work is completed with an estimated expenditure of A$3,100,000: (a) obtain a land access agreement with Sturt Plains Station for regulated activities; (b) acquire, process and interpret 100 km of 2D seismic data; and (c) commence design and planning of a vertical stratigraphic well;
- EP 161: that between March 21, 2024 and March 20, 2027 the following work is completed with an estimated expenditure of A$35,000,000: (a) drill two (2) horizontal exploration wells; (b) geological and geophysical studies; (c) fracture stimulation and testing of the two Year 4 wells; and (d) 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 was 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. Reserved 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*" 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 "Corporate Governance" 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 25, 2026.

Name and Age	Position
Todd Abbott (53)	Chief Executive Officer. On January 10, 2026, the board of directors of the Company appointed Todd Abbott as Chief Executive Officer, effective January 15, 2026. Mr. Abbott has over 25 years of experience driving strategy, fostering efficiency and innovation in the oil and gas industry. He was the Chief Operating Officer of Seneca Resources Company, LLC from 2023 to 2025, the Executive Chair of Oilfield Water Logistics LLC from 2021 to 2022, and held multiple positions, including Senior Vice President of Business Planning and Strategy, at Marathon Oil Corporation from 2018 to 2021. Prior to his time at Marathon Oil Corporation, he served in multiple positions at Pioneer Natural Resources for over a decade. He also has served as an Advisory Board Member for Living Water International since 2022, supporting initiatives that provide clean and sustainable water solutions to communities worldwide. Also since 2022, Mr. Abbott has been an Advisory Board Member of the Zachry Department of Civil and Environmental Engineering at Texas A&M University. Mr. Abbott holds an MBA in Finance and Accounting from the SMU Cox School of Business, and an engineering degree from Texas A&M University.
Eric Dyer (44)	Chief Financial Officer. Eric Dyer joined TR Ltd. as Chief Financial Officer in November 2019. 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. (now S&P Global) and RBC Capital Markets. Mr. Dyer received a Bachelor of Science in Finance from the University of Minnesota.
Faron Thibodeaux (65)	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 after initial gas sales, which commenced in September 2026. 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 eight horizontal wells as operator, six of which have been completed, with two wells (SS1-4H and SS1-6H) drilled and awaiting completion and a ninth well (SS1-2H) currently being drilled. 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 five wells tied into the SPCF. 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 three wells that we are currently drilling, and estimate gross expenses of approximately $25 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 upstream and midstream 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 after initial gas sales which commenced in September 2026, and 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. 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 of the conditions of any such obligation. 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. 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. We did not have any revenue during the reporting period with first gas sales commencing in September 2026. 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, nine 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. For example, during the drilling operations in the Shenandoah South Pilot Project, a downhole mechanical issue in SS2-2H led to it being plugged and sidetracked, SS2-2H-ST1, despite achieving a record horizontal section in the Middle Velkerri B Shale. Additionally, the completion operations for the SS2-5H well were paused due to detected stress in the casing connection, necessitating reinforcement activities before stimulation and completion activities were undertaken in 2026. 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 we 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 are 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. The delivery of the further drilling rigs may be delayed or canceled, 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 an 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 or 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, which depend on numerous factors beyond our control. These factors include, but are 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 an 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 overruns, limitations on our growth and negative effects on our financial condition, results of operations, cash flows and liquidity.

The second and third phases of our business require 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 the 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 they 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.

The inability of one or more third parties who contract with us to meet their obligations to us may adversely affect our financial results.

We may be liable for certain costs if third parties who contract with us or with the operators of our permit areas are unable to meet their commitments under such agreements. We are currently exposed to credit risk through joint interest receivables from our joint venture partners. If any of our partners in which we hold interests are unable to fund their share of the exploration or development expenses, we may be liable for such costs. This could result in such party being in default, which in turn would require the Company and its non-defaulting block partners to pay their proportionate share of the defaulting party's costs during the default period. Should a default not be cured, the Company could be required to pay its share of the defaulting party's costs going forward. In addition, we and the operators of our permit areas contract with third parties to conduct drilling and related services on our development projects and exploration prospects. Such third parties may not perform the services they provide us on schedule or within budget. Furthermore, the drilling equipment, facilities and infrastructure owned and operated by such third parties are highly complex and subject to malfunction and breakdown. Any malfunctions or breakdowns may be outside our control and result in delays, which could be substantial. Any delays in our drilling campaign caused by equipment, facility or infrastructure malfunction or breakdown could materially increase our costs of drilling and cause an adverse effect on our business, financial position and results of operations. We are currently exposed to credit risk through receivables resulting from the sale of our natural gas and cash term deposits held with banks. The inability or failure of our significant customers or counterparties to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. The inability or failure of third parties we contract with to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We are unable to predict sudden changes in creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited and we could incur significant financial losses.

A majority 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.

We may be unable to make accretive acquisitions or successfully integrate acquired businesses or assets, and any inability to do so may disrupt our business and hinder our growth potential.

Our ability to grow may in the future depend in part on our ability to make acquisitions that result in an increase in cash available for distribution. There is intense competition for acquisition opportunities in our industry, and we may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition, do so on commercially acceptable terms or obtain sufficient financing to do so. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. Our failure to achieve consolidation savings, to successfully integrate the acquired businesses and assets into our existing operations or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of 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, subject to policy terms and conditions. This includes insurance coverage related to general and product liability, property, directors and officers, workers compensation, cyber, 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, 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 there may be 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 that 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 “Business and Basis of Preparation” of our audited consolidated financial statements for fiscal years 2025 and 2026 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 2025 and 2026, 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 a deficit of $167.3 million as of June 30, 2025 and $193.4 million as of June 30, 2026. 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 will 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 capital raise in April 2026 and the undrawn portion of the SPCF debt facility provide us with the funds necessary to continue as a going concern over the next 12 months. Our plans are substantially dependent upon the success of commercial production in 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.

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.

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, supply chain issues, changing regulatory environment and tariffs and trade policies, inflation and elevated interest rates, 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 year 2026. 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 2026 compared to fiscal year 2025. 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 2027 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 Iran and the United States, 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 conflicts in Ukraine, Iran 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.

Our business, results of operations and financial condition may be adversely affected by uncertainty and changes in the U.S. regulatory environment and trade policies, including tariffs, trade agreements or other trade restrictions imposed by the U.S. or other governments. Tariffs or other trade restrictions may lead to continuing uncertainty and volatility in U.S. and global financial and economic conditions and commodity markets, declining consumer confidence, inflation and diminished expectations for the economy, which could impact the demand for and price of oil and natural gas, increase the price of supplies and raw materials that we rely on to conduct our business, and could impact interest rates. Changing regulatory environment and trade and tariffs policies could ultimately impact our results of operations and financial condition.

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 is 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, Iran and the United States and between Israel and Hamas as well as other hostilities in the Middle East) have 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 and other disruptions.

We rely on computer systems, hardware, software, technology infrastructure and online sites and networks for both internal and external operations that are critical to our business (collectively, “IT Systems”). We own and manage some of these IT Systems but also rely on third parties for a range of IT Systems and related products and services. Our business faces numerous and evolving security threats, including cybersecurity risks that threaten the confidentiality, integrity and availability of our IT Systems and information that we collect, maintain and process, including personal, confidential and other types of proprietary or sensitive information (collectively, “Confidential 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 Confidential Information, critical infrastructure or capabilities essential to our operations, or otherwise impact the availability, integrity or confidentiality of our IT Systems and Confidential Information and could have a material adverse effect on our reputation, financial position, results of operations and cash flows.

There can be no assurance that our efforts to secure our IT Systems will be effective in protecting such IT Systems, facilities, infrastructure and Confidential 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 in commercial software 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 – that circumvent security controls, evade detection and remove forensic evidence. As a result, we may be unable to detect, investigate, remediate or recover from future attacks or incidents, or to avoid a material adverse impact to our IT Systems, Confidential Information or business. We and certain of our third-party vendors and suppliers have in the past experienced cyberattacks and other incidents, and we expect such incidents to continue to 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 Confidential 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.

We are incorporating artificial intelligence technologies into our processes and these technologies may present business, operational, compliance, cybersecurity, and reputational risks.

Our business is increasingly evaluating the use of and utilizing artificial intelligence ("AI"), machine learning and automation to improve our internal processes and support operational and strategic decisions. The development, deployment and use of these technologies, combined with an evolving and uncertain regulatory environment, may result in new or heightened governmental or regulatory scrutiny, litigation, confidentiality or security risks, reputational harm, liability or other adverse consequences to our business operations, any of which could adversely affect our business, financial condition and results of operations. The use of AI tools can lead to unintended consequences, including the unauthorized use or disclosure of confidential and proprietary information, or the generation of content or outputs that appear correct but are factually inaccurate, misleading, or otherwise flawed. Reliance on such outputs could expose us to risks related to inaccuracies or errors in the output of such technologies. We are in the process of establishing an internal AI strategy and governance including evaluating the costs, benefits, risks and opportunities associated with the use of any AI tools in our business and recommending mitigation measures, as well as developing and implementing an AI use policy across the Company. However, these governance measures may not be effective in all cases, and it is not possible to predict or prevent all of the risks related to the use of AI, machine learning, and automated decision-making technologies. In addition, future changes in laws or developments in the regulatory frameworks governing the use of such technologies and in related stakeholder expectations could restrict or limit our use of AI, increase our compliance costs, or subject us to liability, any of which could adversely affect our ability to develop and use such technologies.

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

We are heavily dependent on our IT Systems, including 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 public scrutiny related to sustainability and 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 sustainability and 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 net zero equity Scope 1 and 2 emissions) 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 sustainability and 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. Further, in response to the evolving regulatory environment and investor expectations, or due to our acquisitions of other companies or assets, we may, periodically, make adjustments to our environmental targets or goals. See "*Attention to sustainability and 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 that are subject to change from time to time. 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 development and decommissioning bonds;
- cost recovery for regulatory approvals;
- securities and orphan well levies;

- reports concerning operations;
- the spacing of wells;
- tenure, landholders, native title holders and traditional Aboriginal owners;
- greenhouse gas emission targets and offset requirements;
- water extraction and disposal;
- environmental assessment;
- remediation or investigation activities for environmental purposes;
- Australian domestic gas reservation policy; 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 our assets, which may in turn impact operational and financial performance. Failure to comply with these laws and regulations may also 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 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, in May 2021, the International Energy Agency released a report in relation to its recommendations for a pathway to achieve global net zero emissions by 2050, which 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 the implementation of certain recommendations.

Shifts in government policy could have varying degrees of impact on our operations and profitability. These impacts could range from loss or reduction in industry incentives, preventing infrastructure development to temporary or permanent 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 the suspension of operations, loss of permits or significant 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) 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 our permits by the relevant authorities. 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; ongoing monitoring 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 for Mining and Energy for the NT Government 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. Further the Minister may direct the holder of a production license to maintain, increase or reduce the rate of recovery of petroleum from the area which could impact profitability. 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 1993 (Cth) and the Aboriginal Land Rights (Northern Territory) Act 1976 (Cth) (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 1984 (NT), which, among other matters, 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 damages arising from personal injuries, property damage, penalties, costs and other losses. 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 about our operations with respect to environmental issues or Indigenous rights, and there is an ongoing risk from existing or future community opposition to our operations. For example, pastoralists whose pastoral leases are subject, in part, to our petroleum interests may refuse to enter into access agreements for us to conduct certain regulated activities that require an access agreement, and we may be 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) seeking orders to prevent part or all of our operations, media campaigns and protests, which could result in significant legal costs and delays. If such community members were successful in their campaigns, operations may be suspended or we may not be able to obtain the permits and approvals or there could be delay in obtaining 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 the development of exploration agreements with native title holders. 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. Additionally, we cannot guarantee that all stakeholders will agree that our negotiations have been conducted consistent with the principle recognized in the United Nations Declaration on the Rights of Indigenous Peoples (UNDRIP) and People of Free, Prior and Informed Consent (FPIC), which may result in operational, reputational, or other adverse impacts to our business.

In addition, we will also need to comply with the Sacred Sites Act 1989 (NT), 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 matters of 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 Sacred Sites Act 1989 (NT) 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 Sacred Sites Act 1989 (NT), regardless of whether or not they are included on the register maintained under the Sacred Sites Act 1989 (NT). Destruction, disturbance or harming protected sites and artifacts may result in us incurring significant civil and/or criminal penalties, and reputational harm all of 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 entering the Safeguard Mechanism, when facility operated Scope 1 emissions exceed 100,000 t-CO2-e per annum, 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 net zero goal with respect to natural gas production. Meeting these requirements and goals may increase our costs of production, and we may be unable to meet these requirements and goals.

Australian law, which includes the National Greenhouse and Energy Reporting Act 2007 (Cth) and the National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2015 (Cth) requires that, upon a facility reaching the relevant threshold of 100,000 t-CO_2-e Scope 1 emissions per fiscal year, we produce natural gas in the Beetaloo on a Scope 1 net zero basis. We also have set an internal net zero goal with respect to natural gas production. To achieve these goals, we may utilize renewables and batteries to supply our operational power needs as well as purchase carbon offsets as required, however there is no guarantee we will achieve such plans. If we are unable to utilize renewables and batteries to supply our operation power needs to the extent we currently expect, if the price of carbon offsets increases or if we have otherwise underestimated the amount of Scope 1 or Scope 2 emissions that we will need to offset, our costs of production will increase further which could have a material adverse effect on the results of operations. The Australian government has announced a review of the Safeguard Mechanism, which is due to commence in the second half of calendar year 2026 and conclude during calendar year 2027. The review will consider key settings including the baseline decline rate beyond 2030 and the threshold for covered facilities.

We may not achieve, and there are potential risks associated with, our growth strategy and vision to become a net zero equity Scope 1 and 2 emissions producer. Achievement of our vision of becoming a net zero equity Scope 1 and 2 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 greenhouse gas 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 environmental, social and governance (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*."

Attention to sustainability and ESG matters and environmental conservation measures may adversely impact our business.

Evolving expectations from regulators, investors, lenders, customers, employees and other stakeholders concerning climate change, sustainability and ESG matters, 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 evolving globally. Companies in the natural gas industry are often the target of activist efforts from both individuals and non-governmental organizations regarding safety, environmental risk and 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 sustainability and 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 inaccurate, 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 sustainability and 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 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 diverging levels of regulation, disclosure-related and otherwise, with respect to ESG matters. For example, starting fiscal year 2027, we will become subject to mandatory climate-related disclosure requirements in Australia under the Australian Sustainability Reporting Standards (including AASB S2 Climate-related Disclosures) and the Corporations Act. We may become subject to additional mandatory climate and sustainability disclosure regimes in other jurisdictions in which we operate including, for example, the European Union's Corporate Sustainability Reporting Directive, California's Climate Corporate Data Accountability Act (SB 253), Climate-Related Financial Risk Act (SB 261) and analogous regimes. These regimes require us to make new and expanded disclosures regarding our climate-related governance, strategy, risk management, metrics and targets, and may differ from one another in scope, methodology, materiality threshold, and assurance requirements. Differences or perceived inconsistencies between our disclosures across these regimes, or between these disclosures and our other public statements (including our Sustainability Report) could expose us to enforcement action, private litigation, regulatory inquiry, or reputational harm. These variations may occur even where the underlying data is accurate, reflecting the application of different regulatory frameworks or the structural necessity of reporting across distinct corporate perimeters and legal entity boundaries (such as regional subsidiary-level data perimeters versus our global consolidated organizational footprint). Additionally, these new obligations will 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. These regulations are not uniform, which may increase the cost and complexity of compliance, as well as associated risks.

Simultaneously, there are efforts by some stakeholders to reduce companies' efforts on certain ESG-related matters. Our efforts to implement or expand sustainability and ESG initiatives and programs may be viewed unfavorably by some stakeholders and expose us to competing and sometimes irreconcilable demands. 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. Responding to these divergent and shifting expectations on both pro-ESG and anti-ESG matters may increase our costs and operational complexity, which could lead to adverse effects on 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 sustainability and 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 sustainability and 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 subsurface and surface impact of unconventional drilling, including concern about the impacts of unconventional drilling for water. In addition, there are many regulatory requirements for us to adhere to including, but not limited to, those specified in the 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) and the Work Health and Safety (National Uniform Legislation) Act 2011 (NT) and Work Health and Safety (National Uniform Legislation) Regulations 2011 (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.

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, laws, and regulations 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 GHG 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 tonnes of CO_2-e emissions per fiscal year will be given a "Zero" GHG baseline. Accordingly, once a shale natural gas facility has exceeded the 100,000 gross t-CO_2-e Scope 1 threshold, the Company must demonstrate that it has achieved Scope 1 net zero emissions, either through operational measures 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 "*Attention to sustainability and ESG matters and environmental conservation measures may adversely impact our business*." In addition, climate change may give rise to physical risks to our operations, including an increased frequency or severity of natural disasters and weather events, such as bushfires, cyclones, flooding, and extreme heat, as well as chronic shifts in temperature and precipitation patterns and water availability in the Northern Territory, any of which could delay or prevent our ability to conduct our activities, which could negatively impact our financial performance.

Evolving 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 commenced litigation against oil and natural gas companies in state or federal courts and tribunals, 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, 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. Activism related to climate change has also been increasing in our industry, and both shareholders and other parties may attempt to effect changes to our business or governance, whether by stockholder proposals, public campaigns, proxy solicitations or otherwise, as applicable. Any of these risks could result in unexpected costs, negative sentiments about us, disruptions in our operations, increases to our operating costs and 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. While various capital providers have subsequently chosen not to invest in fossil fuel energy companies, many have stated that they continue to consider climate-related matters in their strategy and financing decisions. 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 events also 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 is expected to 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 and 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. The effects of 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 related 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 our 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 or remediation 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 covered by insurance. Compliance with these laws requires significant expenditure and non-compliance may potentially result in fines or requests for improvement action from the regulators.

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, suspension or revocation of permits, litigation risk, or financial or civil 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, but not limited to 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 (Cth);
- National Greenhouse and Energy Reporting Act 2007 (Cth);
- Work Health and Safety (National Uniform Legislation) Act 2011 (NT); and
- Waste Management and Pollution Control Act 1998 (NT).

These laws and their respective regulations, as well as state and territory laws and regulations, 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. The damages claimed may be material. In addition, these laws and regulations may restrict the rate of natural gas production or underground injection, disposal, and sequestration of carbon dioxide. There can be no assurance that our environmental compliance 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 or prohibits 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 laws and regulations.

We may be subject to laws and regulation that restrict our ability to cost effectively manage water produced as part of natural gas exploration and production operations. The process of shale extraction involves the injection of stimulation fluid involving water and the recovery of that stimulation fluid to enable gas flows. This water is referred to as flowback. Other waste water is produced during drilling, with drilling and flowback wastewater collectively referred to as "wastewater". Our ability to manage wastewater may impact our ability to undertake exploration and production activities. Wastewater must be either recycled within stimulations or evaporated onsite prior to transport and disposal of any remaining wastewater. The cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability. Where wastewater produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce wastewater in excess of the applicable volumetric permit limits or the quality is not suitable for recycling, we may have to shut in wells, reduce drilling activities, or upgrade facilities for wastewater 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 wastewater 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 the 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, data security and the processing of personal information.

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 also depend on third party vendors in relation to the operation of our business, a number of which process personal information on our behalf. We and our vendors 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 impose transparency obligations, provide residents with rights in relation to their personal information, and impose restrictions on our disclosure of their information.

These requirements, and their application, interpretation and amendment, are constantly evolving and pose increasingly complex compliance challenges. It is also possible that new laws, regulations and other requirements, or amendments to or changes in interpretations of existing laws, regulations and other requirements, may require us to implement new processes, potentially elevate our costs, or require changes to our handling of information or 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 or perceived failure by us to comply with laws, regulations, industry standards and requirements regarding data privacy, data security or the processing of personal information could result in proceedings or actions against us by individuals, consumer rights groups, government agencies, or others. We continue to monitor and assess the impact of these laws, regulations and other requirements, but we could incur significant costs in investigating and defending such claims, and any subsequent adverse outcomes may subject us to significant negative publicity and an erosion of trust. If any of these events were to occur, our business, results of operations, and financial condition could be materially adversely affected.

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/or 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 Environmental, Legal Compliance and Regulatory Matters (Hungary)

If, upon expiry of the currently effective production TOP period in July 2027, the minimum production threshold set out in Section 30/A(3)–(4) of the Mining Act is not met (i.e., planned natural gas production during such period totals 225,500m^3) the mining plot will be cancelled. SZTFH resolution approving the 2026/2027 TOP for the Makó-árok I. mining plot (resolution no. SZTFH-BANYASZ/5240-11/2026) expressly provides that the mining authority will cancel TXM's mining right if the production volumes authorized thereunder are not achieved. Among other obligations and restrictions, the mining authority has not authorized in the TOP approval decision hydraulic fracturing, formation acidizing, gas injection, formation energy replenishment, or water injection for the purposes of hydraulic fracturing or formation energy replenishment.

If the mining plot is cancelled, it is the obligation of the former holder of the mining plot to fulfill, among others, compensation obligations for mining damage (if any), complying with statutory requirements of land remediation and safety, as well as protection of the environment and nature shall be maintained. Accordingly, in case of cancellation the plugging and abandonment of the existing wells will be the obligation of TXM, the ordering of which may be subject to the tendering process described below.

Following cancellation, the mining authority may launch a public tender for the reallocation of the mining plot; however, the duration of such process cannot be estimated in advance. As long as the possibility of re-tendering remains open, the final plugging and abandonment of the wells would normally not be expected (it is not excluded though), as a new license holder may wish to make use of some of the existing wells.

Exploration and production of hydrocarbons in Hungary are governed by a complex and evolving framework of laws and regulations, primarily the Mining Act, environmental protection legislation, nature conservation rules, water management regulations and related secondary legislation. These rules include requirements concerning, inter alia, the authorization and conduct of mining activities, environmental protection, nature conservation, water management and site rehabilitation.

Operators must obtain and maintain a range of permits, approvals and rights, as applicable, including mining rights or concessions, environmental authorizations, environmental impact assessments where required, water abstraction and discharge permits, and land-use rights (surface land access must still be secured separately from the mining rights). Material expenditures are typically required for royalties, financial security for decommissioning and rehabilitation, environmental monitoring, reporting obligations and compliance with the approved technical operational plan. Land access arrangements with surface owners and, where applicable, engagement with local authorities or other stakeholders add further complexity and potential delay.

Drilling and well-work operations, other than maintenance activities, must be notified to the mining authority prior to commencement and may only begin once the designated responsible technical manager has confirmed operational readiness and the required approval is recorded in the mine's safety log. Production from continuously operating wells must be measured at least monthly. Temporarily suspended wells must be secured and regularly inspected under an operator-approved plan; permanently abandoned wells must be securely closed and abandoned in accordance with the applicable mining and technical safety requirements.

Non-compliance with applicable laws, license conditions or environmental standards may result in suspension or termination of operations, revocation or non-renewal of mining rights, substantial administrative fines, civil liability for environmental damage or personal injury, and in serious cases criminal sanctions. Such outcomes could impair the ability to commercialize or retain assets and may have a material adverse effect on operational and financial performance. In addition, acquired assets may carry pre-existing environmental or rehabilitation liabilities that could give rise to further costs or restrictions.

The mining right may be cancelled in particular if the holder fails to provide the required financial security and, following a final authority decision prohibiting the commencement or continuation of mining operations until such security is provided, fails to provide such security within ninety days, or if, within two years following the first sanctioned infringement, the holder commits three further infringements, resulting in cancellation of the mining right upon the fourth infringement, or if operative production, as defined by applicable law, is not commenced within five years of the establishment of the mining plot, or the fee prescribed for the extension of that period is not paid; or if the mining right holder ceases to exist without a legal successor.

Acquisition of a controlling or other qualifying interest in a Hungarian company that holds a mining plot requires the prior approval of the mining authority under the Mining Act. Non-compliance with either requirement renders the acquisition void as regards the mining rights.

Government policy in the energy sector is subject to change and may be influenced by European Union climate and energy-transition objectives, domestic security-of-supply considerations or fiscal measures. Shifts in policy could lead to tighter environmental standards, increased royalties, new restrictions on production, or changes to the concession and licensing regime. The grant or extension of production rights remains discretionary and may be made subject to conditions that affect profitability or operational flexibility.

In addition, operations may be constrained by protected areas, water-resource limitations or other environmental features. Any failure to adapt to new or stricter requirements, or any delay in obtaining necessary authorizations, could increase costs, prolong project timelines or limit the scope of activities, thereby adversely affecting results of operations and financial conditions.

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 significant 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. Our investment in resources to comply with evolving laws, regulations and standards 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 we fail to comply with new laws, regulations and standards, regulatory authorities may initiate legal proceedings against us, and our business may be harmed.

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, 2026 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 $48.3 million.

In addition, all of our facilities are located in Australia, a majority of our officers and employees are residents in Australia and a material proportion 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. The Audit & Risk Management Committee of our board of directors ("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 Mr. 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 Mr. Bryan Sheffield, and certain of our directors ORRIs in certain of the permits we have interests in. On May 12, 2025, TR West, as seller, and the Company, as seller guarantor, and DWE entered into an Asset Sale Agreement. See "Business and Properties—Agreements Relating to the Development of our Assets" in this report and "Related Person Transactions" included in the 2026 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 66⅔% 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 66⅔% 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 2028. 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 2028, 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 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 preparation of our financial statements for the fiscal years ended June 30, 2026 and 2025, we identified deficiencies in our internal control over financial reporting which, in the aggregate, constituted a material weakness as of June 30, 2026. The deficiencies that continue to exist as of June 30, 2026 relate to insufficiently designed and operating internal control over financial reporting and consist of the following: (i) we failed to effectively document management review procedures to validate the completeness and accuracy of transactions and to clearly define and evidence the processes used and the criteria and judgment applied in the performance of critical business processes; and (ii) we failed to fully resolve identified segregation of duties conflicts with system access for designated business and IT privileged users, and as a result the related user access and application change management procedures could not be relied upon for select Company systems.

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. 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.

We anticipate losing our "emerging growth company" status in the next fiscal year and we will be subject to additional public company reporting and disclosure requirements that may increase our legal and compliance costs.

Under the current SEC regulations, we anticipate losing our "emerging growth company" status in the next fiscal year. Once we lose this status, we will no longer be able to take advantage of some or all of the exemptions described above and may be required to, among other things, (i) provide three years of audited financial statements and three years of management's discussion and analysis of financial condition and results of operations disclosure, (ii) comply with the auditor attestation requirement in the assessment of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act (if we are an accelerated filer or large accelerated filer at that time), (iii) comply with any requirement that may be adopted by PCAOB, (iv) comply with certain disclosure and voting obligations regarding executive compensation and (v) adopt revised or new accounting standards on the time schedule applicable to non-emerging growth companies. Any new obligations will make other aspects of our business more difficult, time-consuming or costly and increase demand on our personnel, systems and other resources. For example, to maintain and improve the effectiveness of our disclosure controls and procedures and internal control over financial reporting, we will need to commit significant resources, hire additional staff and provide additional management oversight.

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.

Our outstanding CDIs are listed on the ASX and are 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 likely affects 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 rules 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 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 quoted in U.S. dollars on the NYSE while our CDIs are 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 (the "Committee"), our board of directors 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 board of directors considers cybersecurity risk as part of its risk oversight function and has delegated to the Committee oversight of cybersecurity risks, including oversight of management's implementation of our cybersecurity risk management program.

Our management team, including our Vice President of Information Technology, is responsible for assessing and managing our material risks from cybersecurity threats, and takes steps to stay informed about and monitor efforts to prevent, detect, mitigate, and remediate cybersecurity risks and incidents through various means, which may include information obtained from governmental, public or private sources, including external consultants engaged by us, and alerts and reports produced by security tools deployed in our IT environment. Our management team has developed and implemented a risk management program that includes cybersecurity risks as a risk category and is intended to protect the confidentiality, integrity, and availability of our critical systems and information. Management has primary responsibility for our overall cybersecurity risk management program and 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 periodically on our cyber risk management program, and the Committee reports to the full board of directors regarding its activities, including those related to cybersecurity.

Our cybersecurity risk management program is integrated into our overall risk management program, and shares common methodologies, reporting channels and governance processes that apply across the risk management program to other legal, compliance, strategic, operational, and financial risk areas. 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; maintaining insurance coverage related to cybersecurity matters; and review of risks related to any new third-party IT providers based on our assessment of their criticality to our operations and respective risk profile.

Our Vice President of Information Technology has over 20 years of experience at public companies, including within the energy sector, enterprise technology vendors, and consulting firms. His expertise includes enterprise technology strategy, transformation, governance, vendor management, and operations and initiatives to strengthen cybersecurity, enhance information security posture, and mitigate technology risk. We continue to focus on cybersecurity measures as Tamboran grows.

We have not identified 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, 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, and other disruptions*."

ITEM 3. LEGAL PROCEEDINGS

Other than as described 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 ensure 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 was commenced by ECNT under the Petroleum Act 1984 (NT) and the Petroleum (Environment) Regulations 2016 (NT). ECNT sought 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. On August 25, 2025, the NTCAT granted leave for the substantive proceedings to be withdrawn by the ECNT. This followed the dismissal of the ECNT's stay application, with the NTCAT handing down its reasons for dismissing the application on November 27, 2024 and the dismissal of the ECNT's application to issue summonses and admit further expert reports, with the NTCAT handing down its reasons for dismissing the application on July 15, 2025.

On December 6, 2024, Lock the Gate Alliance Ltd ("Lock the Gate") lodged an Originating Application in the Federal Court of Australia seeking an injunction under s475(2) of the Environment Protection and Biodiversity Conservation Act 1999 (Cth) ("EPBC Act"), to restrain TB1 Operator from conducting the Shenandoah South Pilot Project and a declaration under §21 of the Federal Court of Australia Act 1976 (Cth) that the Shenandoah South Pilot Project is an action which involves unconventional gas development and is likely to have a significant impact on a water resource within the meaning of §§24D and 24E of the EPBC Act (the "Originating Application"). The Originating Application was heard in the Federal Court of Australia from June 23 to 26, and August 14, 2025 before Owens J, who reserved judgment. On June 26, 2026, Owens J delivered judgment in Lock the Gate Alliance Ltd v Tamboran B2 Pty Ltd [2026] FCA 819, finding that Lock the Gate had not established that the Shenandoah South Pilot Project was likely to have a significant impact on a water resource and dismissing the proceedings with costs.

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, 2026, there were 90 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 of this report.

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, 2026.

No shares of the Company's common stock were repurchased during the three months ended June 30, 2026.

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, 2026 and 2025. 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 hold approximately 2.8 million net prospective acres and are the largest acreage holder in the Beetaloo Basin. We intend to continue to develop our resources and regularly review acquisition opportunities that meet our strategic and financial objectives.

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 61.25% working interest in EPs 76, 98 and 117, where we are the operator, and (iii) a 100% working interest in EPs 136 and 143, where we are the operator, all of which are located in the Beetaloo. Refer to our working interest following the completion of several transactions in "Items 1 and 2. Business and Properties" for additional information.

Recent Developments

In July 2026, Tamboran completed the stimulation campaign on the SS2-4H, SS2-5H and SS2-3H wells in the Northern Pilot Area. The program was the first three-well zipper stimulation and the largest stimulation campaign conducted in the Beetaloo Basin, with 178 stages placed across approximately 30,000 lateral feet, including ten stages of locally produced Beetaloo Red Sand in the SS2-5H well. The 2026 three well drilling program on the SS1 pad commenced following mobilization of the H&P FlexRig® Flex 3 rig to the SS1 pad with spudding of the first well on July 2, 2026. The SS1-6H and SS1-4H wells have been drilled and cased to total depth with 9,505-foot and 9,329-foot usable lateral sections, respectively, and the SS1-2H well is currently being drilled. Stimulation of the three SS1 wells is planned for the fourth quarter of calendar year 2026.

Practical completion of the SPP occurred on July 17, 2026 and mechanical completion of the SPCF occurred on July 26, 2026. In early September 2026, Tamboran commenced the commissioning of the SPCF, with first gas sales delivered into the Northern Territory gas market on September 5, 2026 from the Company's Shenandoah South 2 pad to the NT Government at a discounted price (75% of the contract price) to the long-term Gas Sales Agreement, reflecting the interruptible nature of supply during commissioning. Two wells are currently delivering unconstrained rates into the market, with the remaining wells to be brought online as required to deliver nominated volumes, and volumes are expected to ramp up to the plateau of 40 TJ/d in accordance with the Northern Territory Government's nominations. Commissioning activities are expected to be completed in the fourth quarter of calendar year 2026.

In early September 2026, Santos, as operator of EP 161 (Tamboran 25%), spudded the Jibera South 1H well with the Ensign 971 rig, the first of a two well appraisal program in the Beetaloo East depocenter. The Jibera South 1H and Newcastle South 1H wells are planned to be drilled with 10,000-foot horizontal sections targeting the Mid Velkerri B Shale and stimulated and flow tested across up to 60 stages per well, with stimulation planned for mid-2027.

In September 2026, Tamboran and Liberty Energy entered into a non-binding Memorandum of Understanding setting out the intent to extend the hydraulic fracture stimulation and wireline services agreement covering Tamboran's Beetaloo Basin operations, under which Liberty Energy intends to begin phasing lower-emissions pumping equipment into the Beetaloo fleet from 2027. See "Items 1 and 2. Business and Properties—Our Business Plan."

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 2025 and 2026. 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 2027 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 2027. We have in place a 10-year option, of which six years remain, 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:

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

Through June 30, 2026, we had not generated any revenue from natural gas production due to the stage of our operations, which was appraisal drilling and the final stages of midstream construction. No revenue from natural gas production is reflected in our financial statements as first sales occurred after the period end.

Operating Costs and Expenses

During the fiscal year ended June 30, 2026, natural gas production had not commenced. The initial gas sales in September 2026 should be construed as initial test sales. If and when we do commence natural gas production in quantities to generate regular revenue, we will incur additional operating costs and expenses, workover costs, taxes and royalty fees. Our operating costs and expenses consisted of the following during fiscal years 2026 and 2025: 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 corporate assets, the loss on sale of assets due to the sale of rigs in fiscal year 2025, accretion of asset retirement obligations, exploration expenses, LNG feasibility studies, a Checkerboard fee that was settled in shares of common stock in fiscal year 2025, and general and administrative expenses.

Acquisitions

In fiscal year 2026, the Group completed the acquisition of approximately 98.1% of the issued and outstanding equity interests of Falcon Australia and all of the issued and outstanding equity interests of (i) Falcon Hungary, (ii) Falcon Ireland, (iii) Falcon Holdings and (iv) Falcon South Africa.

We may continue to grow our operations and financial results through strategic accretive acquisition opportunities that may arise relevant to our Beetaloo strategy. We regularly review acquisition opportunities and intend to pursue acquisitions that meet our strategic and financial targets. 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 Russia-Ukraine war, the Iran-United States war and the broader Middle East conflict, the changing U.S. regulatory environment and trade and tariffs policies, the Australian domestic gas market reservation policy, 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. These key factors will only affect us when we produce and sell natural gas.

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:

	Years ended June 30,	
	2026	**2025**
Revenue and other operating income	$ —	$ —
Operating costs and expenses		
Compensation and benefits, including stock-based compensation	(12,539)	(9,397)
Consultancy, legal and professional fees	(6,230)	(6,531)
Depreciation and amortization	(7)	(86)
Loss on remeasurement of assets classified as held for sale	—	(376)
Accretion of asset retirement obligations	(1,243)	(1,042)
Exploration expense	(3,336)	(4,112)
Camp expense recoveries, net	(2,527)	—
LNG feasibility study expense	(123)	(6,035)
Checkerboard fee	—	(5,950)
General and administrative	(6,665)	(5,787)
Total operating costs and expenses	(32,670)	(39,316)
Other income (expense)		
Interest income (expense), net	2,659	1,551
Foreign exchange gain (loss), net	(486)	(2,585)
Other income (expense), net	—	726
Total other income (expense)	2,173	(308)
Net loss	(30,496)	(39,624)
Foreign currency translation	11,890	2,768
Less: Total comprehensive income (loss) attributable to noncontrolling interest	(1,141)	(3,254)
Total comprehensive income (loss) attributable to redeemable noncontrolling interest	(68)	—
Total comprehensive loss attributable to Tamboran Resources Corporation stockholders	$ (17,397)	$ (33,602)

Fiscal Years Ended June 30, 2026 and June 30, 2025

Revenue and other operating income. The commissioning phase of the Pilot Project commenced in September 2026 (subsequent to fiscal year 2026). Therefore, we did not realize any revenue and other operating income during fiscal years 2026 and 2025, respectively.

Compensation and benefits, including stock-based compensation. Compensation and benefits, including stock based compensation, increased by $3.1 million during fiscal year 2026, as compared to fiscal year 2025 largely due to period on period increase in headcount, the transition to a calendar year employee bonus schedule, and compensation awarded to the interim and new CEO.

Consultancy, legal and professional fees. Consultancy, legal and professional fees remained fairly consistent period-over-period.

Loss on remeasurement of assets classified as held for sale. Tamboran recognized a loss on assets classified as held for sale amounting to $0.4 million during fiscal year 2025 primarily due to the write down of rig 403 to the fair value less costs to sell. Tamboran disposed of all assets held for sale in fiscal year 2025.

Accretion of asset retirement obligations expense. For fiscal year 2026, an expense for accretion of asset retirement obligations of $1.2 million was recognized. The recognition of such an expense was primarily due to the accretion of asset retirement obligation liabilities in relation to all EPs, inclusive of EPs 76, 98, 117, 136 and 161, as well as the SPCF pad.

Exploration expense. Exploration expense decreased by $0.8 million during fiscal year 2026, as compared to fiscal year 2025, as the prior period had increased activity for topographical, geographical and geophysical studies and other indirect expenditures while the current period had increased indirect expenditure related to our non-operated permits while the operated permits focused on the flow test for SS2-1H and preparation of the stimulation programs of SS2-4H, SS2-5H, and SS2-3H, the costs of which are capitalized.

Camp expense recoveries, net. During the year ended June 30, 2026, expenses for the field camp of $2.5 million were recognized primarily related to camp utilization, camp services, and related consumables. These costs are offset by recoveries from external parties who utilize the camp.

LNG feasibility study expense. In fiscal year 2025, the Group incurred expenses of $6.0 million related to certain studies and pre-front-end engineering and design services related to the NTLNG facility. These studies were substantially completed in fiscal year 2025, therefore, the expense related to these studies was de minimis in fiscal year 2026.

Checkerboard fee. For fiscal year 2025, the Group incurred an expense of $6.0 million related to the satisfaction of certain payment obligations to DWE under the TB1 Joint Venture Agreement. This obligation was satisfied through the issuance of common stock, subsequent to shareholder approval received in November 2024. No such expense was incurred in fiscal year 2026.

General and administrative. General and administrative costs increased by $0.9 million during fiscal year 2026, as compared to fiscal year 2025, primarily as a result of increased expenses related to insurance, headcount, travel, and other office and administrative fees.

Interest Income, net. Interest income, net increased by $1.1 million during fiscal year 2026, as compared to fiscal year 2025, primarily due to interest received from cash at bank and term deposits during the period.

Foreign currency translation. In fiscal year 2026, we recognized a foreign currency translation gain of $11.9 million, primarily due to the strengthening of the Australian Dollar as of June 30, 2026 in comparison to the average rate during the fiscal year 2026. In fiscal year 2025, we recognized a foreign currency translation gain of $2.8 million, primarily due to the strengthening of the Australian Dollar as of June 30, 2025 in comparison to the average rate during the period. 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 primarily due to operating losses incurred for fiscal years 2026 and 2025. 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 sufficient income 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 an exploration and appraisal 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 substantial revenue from production until early calendar year 2027, at the earliest, which will depend upon successful drilling results, completion of commissioning of the gas processing facility, additional and timely capital funding, and access to suitable infrastructure. Until then our primary sources of liquidity are expected to be cash on hand 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, testing program and SPCF commissioning;
- 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, our ability to identify and complete acquisition opportunities and appraisal and development of our prospects.

For the fiscal year ending June 30, 2027, we estimate that we will need to invest approximately $113.3 million to progress our Pilot Project development plans. We expect cash on hand and available funds from the committed undrawn portion of the SPCF debt facility to be sufficient to fund the stimulation and tie-in costs of the SS2-3H, SS2-4H and SS2-5H wells (completed in July and August 2026 ahead of production start-up), drilling and stimulation costs of SS1-6H, SS1-4H and SS1-2H for production tie-in during 2027, long leads for further production wells and committed SPCF construction costs. 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, 2026	June 30, 2025
Cash and cash equivalents	$ 219,135	$ 39,439

As of June 30, 2026, we had $219.1 million in cash and cash equivalents. This balance represents an increase of $179.7 million from June 30, 2025, as a result of proceeds from cash calls, capital raising activities and the Syndicated Facility Agreement offset by consideration paid for the Falcon Acquisition and spending related to operations on the SS2-5H, SS2-3H and SS2-1H pilot wells, construction of the SPCF and other corporate expenditures in the fiscal period.

Capital Commitments

We had the following five-year capital commitments as of June 30, 2026 and June 30, 2025 which are not recognized as liabilities or payable in the consolidated statement of financial position (all dollar amounts are presented in thousands):

	June 30, 2026	June 30, 2025
Capital commitments:		
Sweetpea Petroleum Pty Ltd	$ 24,028	$ 23,115
EP 161	6,024	2,302
Beetaloo Joint Venture	73,322	75,630
Midstream	22,957	9,056

Sweetpea Commitments

As of June 30, 2026, Sweetpea committed to spend $24.0 million related to two licenses, EP 136 with total commitments of $14.5 million and EP 143 with total commitments of $9.6 million.

A renewal application for EP 136 was submitted to the Department of Mining and Energy (“DME”) in November 2025, requesting an extension of the permit for a period of 18 months to January 2031. DME replied in July 2026 and agreed to a permit extension only through July 2030. As such, the Group maintains a minimum work program commitment of $14.5 million.

An application for EP 143 was submitted and approved by the DME in June 2026 requesting a variation of the minimum work program for years 2 and 3. The total minimum work program commitments remained the same at $9.6 million

EP 161

For the EP 161 working interest, we are obligated to contribute our share of expenses to uphold our stake in this permit, for which Santos Limited is the operator. An application was approved in December 2025 to extend the term of the exploration permit and the required work program which includes the drilling and stimulation of two horizontal wells, along with related geological and geophysical studies to March 2027. Our commitment through March 2027 is expected to be $6.0 million based on the minimum work requirements. There are no minimum commitment requirements after March 2027.

Beetaloo Joint Venture

A variation application was submitted to DME in September 2025 to vary the minimum work program for years 3, 4 and 5. Refer to Note 17 for further details. These commitments include an expected spend of $73.3 million related to drilling and multi-stage hydraulic fracturing of four wells, 3D seismic survey, and subsurface studies, with expenditure across EP 76 of $14.1 million, EP 98 of $43.7 million and EP 117 of $15.5 million.

Midstream

As of June 30, 2026, the Group had contractual commitments of approximately $23.0 million relating to the remaining construction and commissioning of the SPCF project, compared to $9.1 million as of June 30, 2025. As of June 30, 2026, construction of the facility was approximately 90% complete and overall project completion was approximately 93%. Given the advanced stage of the project, substantially all of the remaining forecast expenditure required to complete the facility has been contracted and is reflected in the contractual commitment amount above. The $13.9 million increase from the prior year principally reflects the contracting during fiscal year 2026 of the entirety of the commissioning phase and remaining construction, which had not been contracted as of June 30, 2025. All of the committed amount is expected to be settled within six months of the balance sheet date.

Cash Flows

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

	Years Ended June 30,	
	2026	2025
Statement of Cash Flows:		
Net cash used in operating activities	$ (34,597)	$ (29,636)
Net cash used in investing activities	(187,560)	(98,768)
Net cash from financing activities	412,266	101,056

Net Cash Used in Operating Activities

For fiscal year 2026, net cash used in operating activities was $34.6 million during which we incurred a net loss of $30.5 million, compared to net cash used in operating activities for fiscal year 2025 of $29.6 million, during which we incurred a net loss of $39.6 million. The net loss for fiscal year 2026 included the non-cash impacts of depreciation and amortization, stock-based compensation, performance bond facility fees, accretion of asset retirement obligations, interest expense and foreign exchange differences. Additionally, in the year ended June 30, 2026, net unfavorable changes in operating assets and liabilities totaled $12.5 million, primarily consisting of an $8.3 million decrease in accounts payable and accrued expenses due to timing of our pay cycle during the fiscal period, and a $7.8 million increase in prepaid expenses and other assets, partially offset by a $2.9 million decrease in trade and other receivables.

Net Cash Used in Investing Activities

For fiscal year 2026, net cash used in investing activities was $187.6 million compared to $98.8 million for fiscal year 2025. In the current period there was spend on exploration and evaluation activities of $112.0 million in connection with the drilling of the SS2-5H, SS2-3H and SS2-1H pilot wells, $37.3 million of spend related to SPCF, $0.4 million of spend related to sand mining, $3.4 million related to interest on financing lease liabilities, $5.0 million related to interest on borrowings under our Syndicated Facility Agreement, $12.1 million in connection with the Falcon Acquisition and $17.4 million related to the assignment of a note receivable, partially offset by the receipt of the R&D tax incentive of $0.1 million.

Net Cash from Financing Activities

For fiscal year 2026, net cash received from financing activities was $412.3 million compared to $101.1 million received for fiscal year 2025. This increase was primarily due to $291.0 million in net proceeds from the issue of shares in connection with the Company's capital raises in fiscal year 2026 in comparison to net proceeds of $42.9 million received in fiscal year 2025. Other activity in the fiscal year 2026 included $74.5 million attributable to contributions from noncontrolling interest holders to fund their share of cash calls compared to $61.5 million in the prior period, $58.9 million of proceeds from the Syndicated Facility, payment of debt issuance costs of $3.6 million, repayments of finance lease liabilities of $8.2 million and $0.3 million related to the payment of performance bond facility establishment fees.

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. The impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset (or asset group) exceeds its fair value. 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 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 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 are and 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 remediate, 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 differences 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), Binomial Lattice or the Monte-Carlo option-pricing model (for awards that vest based on market conditions). Each of these models includes 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

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 inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Evaluation of Disclosure Controls and Procedures

During the fiscal period covered by this report, our management, with the participation of the Chief Executive Officer and Chief Financial Officer, carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act) as of June 30, 2026. Based on such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as a result of the material weakness in internal control over financial reporting described below, our disclosure controls and procedures were not effective as of June 30, 2026. In light of the material weakness in the Company's internal control over financial reporting described below, we performed additional analysis and other procedures to ensure that our consolidated financial statements were prepared in accordance with GAAP. Accordingly, our management, including the Chief Executive Officer and Chief Financial Officer, has concluded that the consolidated financial statements included in this Annual Report on Form 10-K fairly present, in all material respects, our financial position, results of operations, and cash flows as of and for the periods presented, in accordance with GAAP.

In connection with the preparation of our financial statements for the fiscal years ended June 30, 2026 and 2025, we identified deficiencies in our internal control over financial reporting, which in the aggregate, constituted a material weakness as of June 30, 2026 and 2025, respectively. The deficiencies, which continue to exist, and, in the aggregate, constituted a material weakness as of June 30, 2026, were identified in connection with the preparation of our financial statements for the fiscal year ended June 30 2026, as described below. Certain deficiencies identified in prior periods as described under "Consideration of Previously Identified Deficiencies" below have been deemed to no longer contribute to the material weakness as of June 30, 2026. The deficiencies that continue to exist as of June 30, 2026, which in the aggregate constitute a material weakness, relate to insufficiently designed and operating internal control over financial reporting and consist of the following:

i) The Company failed to effectively document management review procedures to validate the completeness and accuracy of transactions and to clearly define and evidence processes used and criteria and judgment applied in performance of critical business processes.

ii) The Company failed to fully resolve identified segregation of duties conflicts with system access for designated business and IT privileged users; thus related user access and application change management procedures could not be relied upon for select Company systems.

These deficiencies, while relating to different aspects of the Company's internal control environment, are interrelated as the deficiencies affect both the reliability of information used in the financial reporting process and the effectiveness of controls designed to identify potential errors in that information. As a result, management concluded that the deficiencies should be evaluated on an aggregate basis and, collectively, constitute a material weakness in internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal controls over our financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. Tamboran's internal controls over financial reporting are processes designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Due to their inherent limitations, internal controls over financial reporting may not be effective in preventing or detecting misstatements. Additionally, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate due to changes in conditions or that the degree of compliance with policies or procedures may deteriorate.

Management evaluated the effectiveness of Tamboran's internal controls over financial reporting as of June 30, 2026, based upon the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO - 2013"). Based on the assessment using these criteria, Management concluded that, as of June 30, 2026, our internal controls over financial reporting were ineffective to detect a material misstatement due to deficiencies that existed in the design or operation of our internal controls over financial reporting that are considered to be a material weakness as described herein above. 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 the company's annual or interim financial statements will not be prevented or detected on a timely basis.

Notwithstanding the existence of this material weakness in our internal controls over financial reporting, Management believes that Tamboran's consolidated financial statements fairly present in all material respects the

Company's financial condition, results of operations, and cash flows for the periods presented. We continue to evaluate the effectiveness of internal controls and procedures on an on-going basis.

As Tamboran continues to be an emerging growth company, this report does not include an attestation report from our independent registered public accounting firm regarding internal controls over financial reporting.

Remediation Plan for the Material Weakness

In response to the material weakness identified and described above, our management, with the oversight of the Audit & Risk Management Committee of our board of directors, will continue to dedicate significant efforts and resources to further improve our control environment and to take steps to remediate the remaining deficiencies aggregating to the material weakness.

With respect to management review procedures, during fiscal year 2025, we engaged an internal audit firm to assist with the documentation of our processes and internal controls. We continue to 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 continue to hire accounting and finance personnel, or engage technical specialists, who possess the required technical knowledge to ensure reporting requirements are met and segregation of duties are maintained, and procedures for determining, communicating, implementing, and monitoring controls over the period-end financial close and reporting processes are formally documented.

With respect to segregation of duties within our information technology systems, we have restricted administrator access in certain systems and are implementing mitigating controls where restriction is not practicable. We are also implementing a formal segregation of duties review process across our in-scope systems and are updating our change management policy and related documentation requirements.

The material weakness cannot be considered remediated until the newly designed control activity operates for a sufficient period of time and management has concluded, through testing, that the control is operating effectively.

Consideration of Previously Identified Deficiencies

The following deficiencies were previously disclosed as components of our material weakness in our Annual Report on Form 10-K for the year ended June 30, 2025:

i. lack of manage access and manage change IT general controls over our cloud-based enterprise resource planning system.

ii. accounting for complex transactions in accordance with GAAP.

We have concluded that these deficiencies no longer individually or in the aggregate rise to the level of a material weakness as of June 30, 2026. Specifically, we have:

i. Transitioned core financial and operational transactions from the legacy enterprise resource planning system to an enterprise system that is governed by third party security and data handling controls in fiscal year 2025 and formalized design and execution of mitigating activities in fiscal year 2026.

ii. Implemented processes supporting documented technical accounting analysis and review of non-routine and complex transactions, with support from external specialists, where appropriate.

Changes in Internal Control Over Financial Reporting

Other than described above, 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 fiscal year ended June 30, 2026 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, 2026, 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, 2026.

Code of Business Conduct and Ethics

The Company's Code of Business Conduct and Ethics (the "Code of Conduct"), 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 of the Code of Conduct 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 of (to the extent applicable to the Company's directors, executive officers or principal financial officers) the Code of Conduct on its website.

Insider Trading Policy

We have adopted an Insider Trading Policy that governs the purchase, sale, and/or other dispositions of our securities by directors, officers and employees that is reasonably designed to promote compliance with insider trading laws, rules and regulations and NYSE listing standards. A copy of our Insider Trading Policy is filed as Exhibit 19.1 to this report.

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, 2026.

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, 2026.

	Equity Compensation Plan Information		
	(a)	(b)	(c)
Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights[(2)]	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders[(1)]	1,183,106	$ 18.87	1,075,645
Equity compensation plans not approved by security holders	–	–	–
Total	1,183,106	$ 18.87	1,075,645

(1) Consists of the 2024 Equity Award Plan (the "2024 Plan").
(2) Does not include 5,438 shares of unvested restricted stock issued under the 2024 Plan.

The additional information required by this Item 12, as well as 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, 2026.

Australian Disclosure Requirements

In addition to the Company's primary NYSE listing, Common Stock is also quoted in the form of CDIs on the ASX and trades 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 of directors may consider inadequate and encourage persons seeking to acquire control of the Company to first negotiate with the board of directors.

Australian Corporate Governance Statement

The board of directors and employees of the Company are committed to developing, promoting and maintaining a strong culture of good corporate governance and ethical conduct. The board of directors confirms that the Company's corporate governance framework is generally consistent with the ASX's Corporate Governance Council's "Corporate Governance Principles and Recommendations" (4th Edition) ("ASX Governance Recommendations"). The Company's Corporate Governance Statement is available for viewing at https://www.tamboran.com/corporate-governance-statements/. The Corporate Governance Statement sets out the ASX Governance Recommendations and the Company's response as to how and whether it follows those recommendations. The Company's most recent Corporate Governance Statement, dated September 25, 2026, and approved by the board of directors remains accurate as of the date of this Annual Report on Form 10-K.

Issued Capital

As of September 1, 2026, the Company had 34,960,006 shares of Common Stock on issue, of which:

- 28,280,039 shares of Common Stock were held by 90 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 does not include holders whose shares may be held in trust by other entities); and
- 6,679,967 shares of Common Stock were held by CHESS Depositary Nominees Pty Ltd (as Depositary Nominee) on behalf of 5,490 CDI holders, representing 1,335,993,400 CDIs quoted on ASX.

In addition, as of September 1, 2026, the Company had the following unquoted securities on issue:

- 848,724 Units, held by 48 employees and directors of the Company pursuant to the Company's 2024 Plan which entitle the holder (upon vesting) to be issued Common Stock.
- 369,084 Options, held by 7 former Falcon Oil & Gas Limited executives.

Voting Rights

Each holder of Common Stock is entitled to one vote per share of 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 owners 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.

Substantial Stockholders

The information required in relation to 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, 2026.

Distribution of CDI Holders

Below is a distribution schedule of the number of holders of CDI's, at September 1, 2026, and assuming all shares of Common Stock are held as CDIs.

	Number of Holders	**Number of CDIs**	**%**
1-1,000	77	10,693	— %
1,001-5,000	1,107	3,634,471	0.27 %
5,001-10,000	835	6,439,067	0.48 %
10,001-100,000	2,295	91,956,073	6.88 %
100,001 and over	1,176	1,233,953,096	92.36 %
	5,490	1,335,993,400	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 70, based on the closing price of the Company's common stock and CDIs as of September 1, 2026.

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 of September 1, 2026, and assuming all shares of Common Stock are held as CDIs.

	Name	**Number of CDIs Held(1)**	**Percentage of CDIs**
1	Citicorp Nominees Pty Limited	160,428,356	12.008 %
2	Helmerich & Payne International Holdings LLC	105,952,380	7.931 %
3	HSBC Custody Nominees (Australia) Limited	72,706,165	5.442 %
4	BNP Paribas Noms Pty Ltd	41,970,639	3.142 %
5	BNP Paribas Nominees Pty Ltd <IB AU NOMS Retail client>	36,657,062	2.744 %
6	Venture Holdings Sarl SPF	24,167,920	1.809 %
7	Pat Elliott (Tamboran) Limited	23,546,044	1.762 %
8	UBS Nominees Pty Ltd	22,956,403	1.718 %
9	Cameron Richard Pty Ltd <Cameron Richard Super A/C>	21,431,430	1.604 %
10	Warbont Nominees Pty Ltd <Unpaid Entrepot A/C>	16,147,075	1.209 %
11	Richgard No 40 Pty Ltd	14,300,000	1.070 %
12	Bell Potter Nominees Ltd <BB Nominees A/C>	13,000,002	0.973 %
13	BNP Paribas Nominees Pty Ltd <Hub24 Custodial Serv Ltd>	12,531,306	0.938 %
14	Phillip Hollick Pty Ltd <Philly S/F A/C>	11,633,471	0.871 %
15	Jufran Carbon Pty Limited	11,105,364	0.831 %
16	HSBC Custody Nominees (Australia) Limited <NT-Comnwlth Super Corp A/C>	10,746,305	0.804 %
17	John R Hislop	10,622,806	0.795 %
18	Mr. Archibald Geoffrey Loudon	10,054,187	0.753 %
19	HSBC Custody Nominees (Australia) Limited - A/C 2	9,681,516	0.725 %
20	Mr. Brian Thomas Clayton & Mrs. Janet Clayton	8,267,686	0.619 %

(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 Plan or to satisfy the entitlements of the holders of options or other rights to acquire securities granted under the 2024 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, 2026.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Our independent registered public accounting firm is Ernst & Young (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, 2026.

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 89.

(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
2.1+	Arrangement Agreement, by and among the Company, Australia Sub, U.S. Sub and Falcon, dated September 30, 2025 (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K filed on September 30, 2025, File No. 001-42149, and incorporated herein by reference).
2.2	Amending Agreement (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K dated April 6, 2026, File No. 001-42149, and incorporated herein by reference).
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 Current Report on 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 as Exhibit 4.4 to the Company's Annual Report on Form 10-K for the year ended June 30, 2024, File No. 001-42149, and incorporated herein by reference).
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 Equity 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 Equity 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 Equity 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).
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).

Exhibit number	Description
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+	Agreement, by and among Tamboran Resources Corporation, Bryan Sheffield, Sheffield Holdings, LP and certain other affiliated entities party thereto, dated July 27, 2025 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated July 27, 2025, File No. 001-42149, and incorporated herein by reference).
10.14†	Letter Agreement between the Company and Richard Stoneburner, dated October 15, 2025 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K/A filed on October 17, 2025, File No. 001-42149, and incorporated herein by reference).
10.15	Separation Deed, between Tamboran Services Pty Ltd and Joel Riddle, dated July 28, 2025 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated July 27, 2025, File No. 001-42149, and incorporated herein by reference).
10.16†	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).
10.17†	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).
10.18†	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).
10.19†	Employment Agreement between Tamboran Resources USA, LLC and Todd Abbott dated January 10, 2026 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated January 10, 2026, File No. 001-42149, and incorporated herein by reference).
10.20	Confirmatory Side Letter between Tamboran Resources Corporation and Todd Abbott, dated January 15, 2026 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated January 10, 2026, File No. 001-42149, and incorporated herein by reference).
10.21	Director Nominating Agreement, dated June 28, 2024, between Tamboran Resources Corporation and Sheffield Holdings, LP (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated June 28, 2024, File No. 001-42149, and incorporated herein by reference).
10.22†	Restricted Stock Award Notice and Agreement for Fredrick Barrett pursuant to Tamboran Resources Corporation 2024 Equity Award Plan dated January 22, 2025 (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2025, File No. 001-42149, and incorporated herein by reference).
10.23	Performance Bond Facility Agreement, dated December 19, 2024, by and among Tamboran (West) Pty Limited, as borrower, Tamboran Resources Pty Ltd, as guarantor, and Macquarie Bank Limited, as lender (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated December 31, 2024, File No. 001-42149, and incorporated herein by reference).
10.24	Deed of Guarantee and Indemnity, dated December 19, 2024, between Tamboran Resources Corporation, as guarantor, and Macquarie Bank Limited, as lender (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated December 31, 2024, File No. 001-42149, and incorporated herein by reference).
10.25	Syndicated Facility Agreement, between SPCF Financing Pty Ltd, Macquarie Bank Limited, Evolution Trustees Limited as trustee for the Alpha Wave Credit (Australia) Trust, Global Loan Agency Services Australia Specialist Activities Pty Limited, and Global Loan Agency Services Australia Nominees Pty Ltd, among others, dated September 29, 2025 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K dated September 29, 2025, File No. 001-42149, and incorporated herein by reference).
10.26	Deed of Guarantee and Indemnity, between Tamboran Resources Corporation, Tamboran Resources Pty Ltd, Tamboran (West) Pty Limited, and Global Loan Agency Services Australia Nominees Pty Ltd, dated September 29, 2025 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K dated September 29, 2025, File No. 001-42149, and incorporated herein by reference).

Exhibit number	Description
10.27	NTG Guarantee, between Northern Territory of Australia, Macquarie Bank Limited, Evolution Trustees Limited as trustee for the Alpha Wave Credit (Australia) Trust, and SPCF Financing Pty Ltd, dated September 29, 2025 (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K dated September 29, 2025, File No. 001-42149, and incorporated herein by reference).
10.28	Asset Sale Agreement – Beetaloo Acreage Acquisition, dated May 12, 2025, between Tamboran (West) Pty Limited, Tamboran Resources Corporation, and Daly Waters Energy, LP (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K dated May 12, 2025, File No. 001-42149, and incorporated herein by reference).
10.29	Second Amended and Restated Joint Venture and Shareholders Agreement, dated May 12, 2025, between Tamboran (West) Pty Limited, Tamboran Resources Pty Ltd, Daly Waters Energy, LP, and Tamboran (B1) Pty Ltd (filed as Exhibit 10.5 to the Company's Current Report on Form 8-K dated May 12, 2025, File No. 001-42149, and incorporated herein by reference).
10.30	Origin Fourth Amended and Restated Royalty Deed, between Origin Energy B2 Pty Ltd, Falcon Oil & Gas Australia Limited, Tom Duggan Family Limited Partnership LLP, Territory Oil & Gas LLC, and Malcolm John Gerrard, dated September 23, 2022 (filed as Exhibit 10.28 to the Company's Annual Report on Form 10-K for the year ended June 30, 2025, File No. 001-42149, and incorporated herein by reference).
10.31++	Deed of Addendum – Joint Venture and Shareholders Agreement, by and among TR West, TR Ltd., DWE and TB1, dated March 20, 2026 (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on March 20, 2026, File No. 001-42149, and incorporated herein by reference).
10.32++	Deed of Addendum – Asset Sale Agreement – Beetaloo Acreage Acquisition, by and among TR West, the Company, DWE and Elliott, dated March 20, 2026 (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K filed on March 20, 2026, File No. 001-42149, and incorporated herein by reference).
19.1	Insider Trading Compliance Policy (filed herewith).
21	Subsidiaries of the Company (filed herewith).
23	Consent of Independent Registered Public Accounting Firm (filed herewith).
24	The Company's Power of Attorney (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 as Exhibit 97.1 to the Company's Annual Report on Form 10-K for the year ended June 30, 2024, File No. 001-42149, and incorporated herein by reference).
101	Interactive data files (formatted as Inline XBRL).
104	Cover Page Interactive Data File (formatted as iXBRL and contained in Exhibit 101).

** 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.

++ Confidential information has been omitted because it is both (i) not material and (ii) is the type of information that the Company treats as private or confidential pursuant to Item 601(b)(10) 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/ Todd Abbott
Name:	Todd Abbott
Title:	Chief Executive Officer

Date: September 25, 2026

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/ Todd Abbott Todd Abbott	Chief Executive Officer (Principal Executive Officer)	September 25, 2026
/s/ Eric Dyer Eric Dyer	Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)	September 25, 2026
/s/ Richard Stoneburner Richard Stoneburner	Director	September 25, 2026
/s/ Fred Barrett Fred Barrett	Director	September 25, 2026
/s/ Patrick Elliott Patrick Elliott	Director	September 25, 2026
/s/ The Hon Andrew Robb AO The Hon Andrew Robb AO	Director	September 25, 2026
/s/ David Siegel David Siegel	Director	September 25, 2026
/s/ Jeffrey Bellman Jeffrey Bellman	Director	September 25, 2026
/s/ Ryan Dalton Ryan Dalton	Director	September 25, 2026
/s/ Phillip Pace Phillip Pace	Director	September 25, 2026
/s/ Scott Sheffield Scott Sheffield	Director	September 25, 2026

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

To the Stockholders 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, 2026 and 2025, the related consolidated statements of operations and comprehensive loss, stockholders' equity and cash flows for each of the two years in the period ended June 30, 2026, 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, 2026 and 2025, and the results of its operations and its cash flows for each of the two years in the period ended June 30, 2026, 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 consolidated financial statements, the Company has suffered recurring losses from operations that raise substantial doubt 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 25, 2026

TAMBORAN RESOURCES CORPORATION
CONSOLIDATED BALANCE SHEETS (In thousands, except share and per share amounts)

	Note	June 30, 2026	June 30, 2025
ASSETS			
Current assets			
Cash and cash equivalents	2	$ 219,135	$ 39,439
Restricted cash	2	11,960	5,722
Trade and other receivables:			
Joint interest billings		1,472	8,191
ATO receivable		3,735	1,219
Other receivables		430	222
Prepaid expenses and other current assets		6,461	1,903
Total current assets		243,193	56,696
Natural gas properties, successful efforts method:			
Unproved properties	5	807,036	342,314
Assets under construction - natural gas equipment	5	72,287	24,441
Property, plant and equipment, net	5	744	308
Operating lease right-of-use assets	6	2,705	1,549
Finance lease right-of-use asset	6	14,345	16,544
Prepaid expenses and other non-current assets		13,672	4,610
Total non-current assets		910,789	389,766
TOTAL ASSETS		$ 1,153,982	$ 446,462
LIABILITIES, REDEEMABLE NONCONTROLLING INTERESTS AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued expenses	7	$ 73,742	$ 20,457
Advance against joint interest billings	4	—	450
Current portion of operating lease obligations	6	1,897	391
Current portion of finance lease obligation	6	14,410	15,307
Other current liabilities		3,008	—
Total current liabilities		93,057	36,605
Operating lease obligations	6	1,018	1,175
Finance lease obligation	6	8,354	9,523
Asset retirement obligations	9	22,138	9,649
Long-term debt, net	8	59,043	—
Other non-current liabilities		811	57
Total non-current liabilities		91,364	20,404
Total liabilities		184,421	57,009
Commitments and contingencies (Note 15)			
Redeemable noncontrolling interest		1,863	—
Stockholders' equity			
Common stock, $0.001 par value; 10,000,000,000 common stock authorized; 34,872,663 and 16,717,289 common stock issued and outstanding as of June 30, 2026 and 2025, respectively		35	17
Additional paid-in capital		990,356	464,407
Accumulated other comprehensive loss		(812)	(9,421)
Accumulated deficit		(193,355)	(167,281)
Total Tamboran Resources Corporation stockholders' equity		796,224	287,722
Noncontrolling interest		171,474	101,730
Total stockholders' equity		967,698	389,452
TOTAL LIABILITIES, REDEEMABLE NONCONTROLLING INTERESTS AND STOCKHOLDERS' EQUITY		$ 1,153,982	$ 446,462

The accompanying notes are an integral part of these consolidated financial statements. Certain amounts may not add up or recalculate due to rounding.

TAMBORAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE LOSS
(In thousands, except share and per share amounts)

	Note	For the years ended June 30, 2026	2025
Revenue and other operating income		$ —	$ —
Operating costs and expenses			
Compensation and benefits, including stock-based compensation		(12,539)	(9,397)
Consultancy, legal and professional fees		(6,230)	(6,531)
Depreciation and amortization		(7)	(86)
Loss on remeasurement of assets classified as held for sale		—	(376)
Accretion of asset retirement obligations	9	(1,243)	(1,042)
Exploration expense		(3,336)	(4,112)
Camp expense recoveries, net		(2,527)	—
LNG feasibility study expense		(123)	(6,035)
Checkerboard fee		—	(5,950)
General and administrative		(6,665)	(5,787)
Total operating costs and expenses		(32,670)	(39,316)
Loss from operations		(32,670)	(39,316)
Other income (expense)			
Interest income (expense), net		2,659	1,551
Foreign exchange gain (loss), net		(486)	(2,585)
Other income (expense), net		—	726
Total other income (expense)		2,173	(308)
Net loss		(30,496)	(39,624)
Less: Net loss attributable to noncontrolling interest		(4,422)	(2,722)
Less: Net loss attributable to redeemable noncontrolling interest		(1)	—
Net loss attributable to Tamboran Resources Corporation stockholders		$ (26,073)	$ (36,902)
Comprehensive income (loss)			
Net loss		$ (30,496)	$ (39,624)
Other comprehensive income (loss)			
Foreign currency translation		11,890	2,768
Total comprehensive income (loss)		(18,606)	(36,856)
Less: Total comprehensive income (loss) attributable to noncontrolling interest		(1,141)	(3,254)
Less: Total comprehensive income (loss) attributable to redeemable noncontrolling interest		(68)	—
Total comprehensive loss attributable to Tamboran Resources Corporation stockholders		$ (17,397)	$ (33,602)
Net loss per common stock			
Basic and diluted	13	$ (1.161)	$ (2.517)
Weighted-average number of common stock outstanding			
Basic and diluted	13	22,463,972	14,661,192

The accompanying notes are an integral part of these consolidated financial statements. Certain amounts may not add up or recalculate due to rounding.

TAMBORAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In thousands)

	Common stock	Additional paid-in capital	Accumulated other comprehensive loss	Accumulated deficit	Total Tamboran Resources Corporation stockholders' equity	Noncontrolling interest	Total stockholders' equity
Balance as of July 1, 2024	$ 14	$ 404,594	$ (11,513)	$ (130,380)	$ 262,715	$ 44,971	$ 307,686
Issuance of common stock under greenshoe option, net of issuance cost	—	6,930	—	—	6,930	—	6,930
Issuance of common stock as Checkerboard fee	—	5,950	—	—	5,950	—	5,950
Issuance of common stock, net of issuance cost	2	35,309	—	—	35,311	—	35,311
Shares yet to be issued	—	5,321	—	—	5,321	—	5,321
Contributions from noncontrolling interest holders	—	—	—	—	—	58,805	58,805
Stock-based compensation	—	6,303	—	—	6,303	—	6,303
Foreign exchange translation	—	—	2,092	—	2,092	676	2,768
Net loss	—	—	—	(36,901)	(36,901)	(2,723)	(39,624)
Balance as of June 30, 2025	17	464,407	(9,421)	(167,281)	287,722	101,730	389,452
Issuance of common stock, net of issuance cost	18	517,918	—	—	517,936	—	517,936
Issuance of shares against vested equity awards	—	324	—	—	324	—	324
Contributions from noncontrolling interest holders	—	—	—	—	—	70,885	70,885
Stock-based compensation	—	7,707	—	—	7,707	—	7,707
Foreign exchange translation	—	—	8,609	—	8,609	3,281	11,890
Net loss	—	—	—	(26,074)	(26,074)	(4,422)	(30,496)
Balance as of June 30, 2026	$ 35	$ 990,356	$ (812)	$ (193,355)	$ 796,224	$ 171,474	$ 967,698

The accompanying notes are an integral part of these consolidated financial statements. Certain amounts may not add up or recalculate due to rounding.

TAMBORAN RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS (In thousands)

	For the years ended June 30,	
	2026	**2025**
Cash flows from operating activities:		
Net loss	$ (30,496)	$ (39,624)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation and amortization	7	86
Stock-based compensation	4,404	4,355
Foreign exchange (gain) loss, net	486	2,585
Performance bonds Facility Fee	2,205	—
Loss on remeasurement of assets classified as held for sale	—	376
Accretion of asset retirement obligations	1,243	1,042
Checkerboard fee	—	5,950
Accrued interest income	(271)	—
Interest expense	334	381
Changes in operating assets and liabilities:		
Trade and other receivables	2,859	(1,275)
Prepaid expenses and other assets	(7,845)	(180)
Accounts payable and accrued expenses	(8,263)	(3,300)
Other non-current liabilities	740	(32)
Net cash used in operating activities	(34,597)	(29,636)
Cash flows from investing activities:		
Payments for property, plant and equipment	(415)	(290)
Payments for exploration and evaluation	(112,029)	(94,201)
Payments for assets under construction	(37,289)	(15,637)
Payment of interest on finance lease liabilities	(3,406)	(2,799)
Payment of interest on borrowings	(4,960)	—
Payment for Falcon Acquisition, including transaction costs, net of cash acquired	(12,146)	—
Payments in relation to assignment of notes receivable	(17,435)	—
Proceeds from sale of assets held for sale	—	7,990
Proceeds from government grants for exploration	120	6,169
Net cash used in investing activities	(187,560)	(98,768)
Cash flows from financing activities:		
Proceeds from issue of common stock	308,498	46,092
Contributions received from noncontrolling interest holders	74,517	61,457
Advance contributions received from noncontrolling interest holders	—	450
Proceeds from issue of common stock, awaiting issuance	—	5,722
Common stock issue transaction costs	(17,517)	(3,194)
Proceeds from borrowings	58,883	—
Payment of debt issuance costs	(3,619)	—
Payment of transaction costs on common stock, awaiting issuance	—	(401)
Advance payment of common stock issue transaction costs	—	(768)
Payment of performance bond facility establishment fee	(271)	(536)
Repayment of lease liabilities	(8,225)	(7,766)
Net cash from financing activities	412,266	101,056
Net increase (decrease) in cash and cash equivalents and restricted cash	190,108	(27,348)
Cash and cash equivalents and restricted cash at the beginning of period	45,161	74,746
Effects of exchange rate changes on cash and cash equivalents	(4,174)	(2,237)
Cash and cash equivalents and restricted cash at the end of period	$ 231,095	$ 45,161
Supplemental cash flow information:		
Non-cash investing and financing activities:		
Accrued capital expenditure	$ 41,205	$ 7,959

Accrued stock issuance costs		—		(657)
Asset retirement obligations		(229)		(524)
Stock-based compensation reserve		(7,707)		(6,303)
Contribution receivable from noncontrolling interest holders		1,472		7,051
Operating lease right-of use assets and lease liabilities		1,281		587
Interest accrued on finance lease liabilities		(284)		(492)
Finance lease right-of-use assets and lease liabilities		(1,858)		(7,760)
Accrued debt issuance costs		—		—
Interest and fee payable		(1,060)		—
Non-cash finance lease costs capitalized to unproved properties		8,755		10,106
Non-cash equity considerations		2,188		—
Accrued transaction costs		10,375		—
Equity consideration for Falcon Acquisition	$	226,819	$	—

The accompanying notes are an integral part of these consolidated financial statements. Certain amounts may not add up or recalculate due to rounding.

Note 1 – Business and Basis of Preparation

General

Tamboran 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 ("NT") of Australia. The Group is in the exploration and appraisal stage with a 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"), NT Australia. To date, the Group has not determined whether the Tenements contain any natural gas reserves that are economically recoverable. Further, the Group had no revenues from its gas operations as of June 30, 2026.

On May 28, 2026, the Group acquired from Falcon Oil & Gas Ltd. ("Falcon Canada") approximately 98.1% of the issued and outstanding equity interests of Falcon Oil & Gas Australia Limited ("Falcon Australia") and all of the issued and outstanding equity interests of (i) TXM Oil and Gas Exploration Kft. ("Falcon Hungary"), (ii) Falcon Oil & Gas Ireland Limited ("Falcon Ireland") (iii) Falcon Oil & Gas Holdings Ireland Limited ("Falcon Holdings") and (iv) Falcon Exploration and Production South Africa (Pty) Ltd ("Falcon South Africa"). Refer to Note 3 for additional discussion.

Tamboran operates in one reportable segment as a single business unit. Refer to Note 14 for additional discussion.

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, 2026, the Group had:

- not generated revenues since inception, and will not generate earnings in the next twelve months sufficient to satisfy all liabilities in the ordinary and usual course of business;
- a working capital surplus of $138.2 million arising from an increase in cash and cash equivalents due to the capital and other fundraising activities during the period;
- net long-term debt drawn down of $59.0 million related to the construction of the Sturt Plateau Compression Facility ("SPCF") plus associated financing costs;
- an accumulated deficit of $193.4 million since inception; and
- significant expenditures planned for natural gas properties in the next twelve months.

While several of these conditions raise substantial doubt regarding the Group's ability to continue as a going concern for the twelve months following the date these consolidated financial statements were available for issuance, the Group has achieved several milestones during the period, which indicate positive progress toward addressing this substantial doubt in future periods. These milestones include the completion of the institutional offering of $180.4 million and the completion of the retail offering of $17.4 million in the last quarter of the fiscal year, which have significantly strengthened the Group's liquidity position and alleviated the need, in the near term, to pursue certain previously contemplated plans, such as a farm-down transaction. Construction on the SPCF facility has been completed and the commissioning phase is well underway.

The Group's ability to continue as a going concern remains dependent on the successful execution of its operational plans, including stimulation of the remaining three wells, tie-in of the wells to the SPCF, and completion of commissioning of the SPCF. Based on progress achieved to date and the Group's current execution plan, management expects to be better positioned to evaluate the alleviation of substantial doubt in connection with future reporting periods, subject to continued successful execution of these operational plans and funding of future commitments.

Although the Group's cash flow forecast indicates that it will maintain a positive cash position throughout the twelve months following the date these consolidated financial statements were available for issuance, the Group has minimum work commitments under its exploration permits, including commitment wells required to be drilled and stimulated within specified permit years, that fall due shortly after the end of that twelve-month period. Funding for those commitments is expected to require additional equity or debt funding, farm-down or asset sale proceeds, or a variation or extension of the relevant permit work programs. If the Group is unable to secure such funding or obtain a variation, it may be unable to satisfy those commitments and could lose its rights in the affected permits.

As of the date of this report, there can be no assurance that the Group will be successful in executing these plans; however, management is actively progressing these programs in accordance with its development strategy.

Accordingly, these consolidated financial statements do not include any adjustments related to the recoverability and classification of recorded assets and 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 of Consolidated Financial Statements

The accompanying consolidated financial statements have been prepared in conformity with the accounting principles generally accepted in the United States of America ("GAAP") and rules and regulations of the Securities and Exchange Commission ("SEC").

In the current fiscal year, the Group changed the presentation of the audited consolidated financial statements to thousands and, as a result, any necessary rounding adjustments have been made to prior year disclosed amounts. Certain amounts in the Group's consolidated financial statements may not sum or recalculate due to rounding.

Management's Use of Estimates

The preparation of the Group's consolidated financial statements in conformity with GAAP requires management to make judgments, 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 judgments, 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, the determination of whether an acquisition represents a business combination or an asset acquisition, 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.

Principles of Consolidation

These consolidated financial statements include the accounts of the Company, all of its wholly owned subsidiaries and the variable interest entities ("VIEs"), 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.

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 Income (Loss)," a separate component of stockholders' equity.

Foreign Currency Transactions

Foreign currency transactions are translated into the Company'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 fiscal year-end exchange rates of monetary assets and liabilities denominated in foreign currencies are recognized in the consolidated statements of operations and comprehensive loss.

Acquisitions

The Group accounts for business combinations and asset acquisitions in accordance with ASC 805, *Business Combinations*. For each transaction of this nature, management applies a screen test to evaluate if substantially all of the fair value of the gross assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets to determine whether the transaction should be accounted for as an asset acquisition or business combination.

When an acquisition does not meet the definition of a business combination because either: (i) substantially all of fair value of the gross assets acquired is concentrated in a single identifiable asset, or group of similar identified assets, or (ii) the acquired entity does not have an input and a substantive process that together significantly contribute to the ability to create outputs, the Group accounts for the acquisition as an asset acquisition. In an asset acquisition, goodwill is not recognized, but rather, any excess purchase consideration over the fair value of the net assets acquired is allocated on a relative fair value basis to the identifiable net assets as of the acquisition date and any direct acquisition-related transaction costs are capitalized as part of the purchase consideration.

For business combinations, the acquisition method is applied, and identifiable assets acquired and liabilities assumed are generally recognized at their acquisition-date fair values. The excess of the purchase price over the fair value of net identifiable assets is recorded as goodwill; if the fair value of net assets exceeds the purchase price, a gain on bargain purchase is recognized in earnings after reassessment. Noncontrolling interests are measured at fair value. Transaction costs are expensed as incurred.

Cash and Cash Equivalents and Restricted Cash

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.

Restricted cash as of June 30, 2026 represents amounts held in a payment reserve account that serves as a security for servicing of expected future interest and commitment fee payments over the term of the long-term debt up to the end of the loan availability period. Restricted cash as of June 30, 2025 represents amounts related to proceeds received in advance in respect of the common stock pending issuance on that date. The following table is a reconciliation of the total cash and cash equivalents and restricted cash in the accompanying consolidated statements of cash flows and their corresponding balance sheet presentation (in thousands):

	June 30,	
	2026	**2025**
Cash and cash equivalents	$ 219,135	$ 39,439
Restricted cash	11,960	5,722
Total cash, cash equivalents and restricted cash	**$ 231,095**	**$ 45,161**

Trade and Other Receivables

As of June 30, 2026 and 2025, the Group's trade and other receivables were primarily related to unpaid cash calls ("joint interest billing") and goods and services tax receivable from the Australian Taxation Office ("ATO"). As of June 30, 2026 and 2025, the Group had $1.5 million and $8.2 million receivable, respectively, from joint interest billing.

Trade and other receivables 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's operations are in the exploration and appraisal stage and has not yet realized any revenues from 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. The impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset (or asset group) exceeds its fair value.

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.

The Group capitalizes borrowing costs for assets under construction. Upon the asset becoming available for use, capitalized borrowing costs, as a portion of the total cost of the asset, are depreciated over the estimated useful life of the related asset.

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

Sand mining properties and other development/testing costs, which are referred to collectively as sand mining permits, include acquisition costs, and the cost of other development/testing work, all of which are capitalized. Depletion expense related to sand mining permits are recorded from the date the sand mining property is placed into service, based on units-of-production (as sand is extracted) and estimates of sand reserves. The impact of revisions to sand reserve estimates is recognized on a prospective basis.

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 recognized in the profit or loss.

Leases

As a Lessee

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.

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.

Deferred Debt Issuance Costs

The Group presents unamortized deferred debt issuance costs related to the establishment of a Performance Bond Facility Agreement (the "Facility Agreement") as a component of "Prepaid expenses and other non-current assets" on its consolidated balance sheet because the outstanding balance under this Facility Agreement may fluctuate as the Group borrows and repays the relevant amounts. The Group amortizes the deferred debt issuance costs over the remaining term of the Facility on a straight-line basis which is reported within "interest income (expense), net" in the consolidated statements of operations and comprehensive loss.

The Group initially recognizes the establishment of other third party-fees related to the long-term debt as a component of "Prepaid expenses and other non-current assets" on its consolidated balance sheet. As and when, the Group draws down funds from the long-term debt facility, these costs are reclassified (on proportionate basis) and presented as a direct deduction from the carrying amount of the debt liability. These costs are amortized to the asset under construction over the contractual term of the debt using the effective interest rate method.

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 is 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 for 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 Plans

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 $0.8 million and $0.7 million towards the superannuation plan during the years ended June 30, 2026 and 2025, respectively.

Stock-based Compensation

The Group applies the provisions of ASC 718, *Compensation – Stock Compensation*, 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 appropriate option pricing models (depending on the features of options) on the date of the grant. These option pricing models require the input of highly subjective assumptions, including, the term of the awards, the impact of dilution, the CDI/common stock 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.

Noncontrolling Interests

Noncontrolling interests represent the portions of certain consolidated subsidiaries that are owned by third-parties. The Group records noncontrolling interests in accordance with ASC 480, *Distinguishing Liabilities from Equity*. Noncontrolling interests are reported as a component of shareholders' equity, unless they are considered redeemable. Noncontrolling interest are adjusted by the noncontrolling interest holder’s proportionate share of the relevant subsidiaries’ earnings or losses each period and any distributions that are paid.

Noncontrolling interests are considered mandatorily redeemable when they are subject to an unconditional obligation to be redeemed by both parties on a specified date or on the occurrence of a specified event that is certain to occur and is to be redeemed via the transfer of assets. Mandatorily redeemable noncontrolling interests are presented as liability-based financial instruments and are remeasured on a recurring basis to the expected redemption value as part of interest expense, net in our consolidated statement of operations. The carrying amount of these noncontrolling interests are not reduced below the initial measurement amount.

The redeemable noncontrolling interests which are subject to a redemption provision that is outside of our control are recognized as Redeemable noncontrolling interest between total liabilities and stockholders’ equity on the Group’s consolidated balance sheet. These redeemable noncontrolling interests are initially recorded at fair value and subsequently adjusted with the noncontrolling interest holder’s proportionate share of the relevant subsidiaries’ earnings or losses each period and any distributions that are paid.

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, 2026 and 2025.

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 9 for fair value measurement of asset retirement obligations. Refer to Note 3 for fair value measurement of noncontrolling interests in Falcon Australia.

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 receivables, prepaid expenses, other assets, accounts payable, accrued expenses and other current liabilities approximate their fair values.

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 to be realized on examination. For tax positions not meeting the “more likely than not” test, no tax benefit is recorded.

As of June 30, 2026 and 2025, 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, 2026 and 2025.

Net Earnings (Loss) Per Share

Basic earnings (loss) per share is calculated by dividing earnings (loss) attributable to the owners of the Company by the weighted average number of common stock outstanding during the fiscal year, adjusted for bonus elements in common stock issued during the fiscal year (if any).

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 fiscal years ended June 30, 2026 and 2025.

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 May 2026, the FASB issued ASU 2026-02, Environmental Credits and Environmental Credit Obligations (Topic 818), which establishes guidance for the recognition, measurement, presentation, and disclosure of certain environmental credits and environmental credit obligations. This standard is effective for fiscal years beginning after December 15, 2027, including interim reporting periods within those annual reporting periods, with early adoption permitted as of the beginning of a fiscal year. Management is currently evaluating the impact this standard will have on the Group's consolidated financial statements.

In December 2025, the Financial Accounting Standards Board ("FASB") issued ASU 2025-12, *Codification Improvements* ("ASU 2025-12"). ASU 2025-12 clarifies or otherwise modifies GAAP in a number of areas. The standard is effective for all entities for annual reporting periods beginning after December 15, 2026, and for interim periods within those annual reporting periods. Early adoption is permitted as of the beginning of an annual reporting period and adoption can be applied on prospectively or retrospectively, as well as on an issue-by-issue basis. The Group does not expect any material impact on its consolidated financial statements.

In December 2025, the FASB issued ASU 2025-11, *Interim Reporting (Topic 270): Narrow-Scope Improvements* ("ASU 2025-11"). ASU 2025-11 clarifies interim disclosure requirements, including providing a comprehensive list of interim disclosure requirements under GAAP and a disclosure principle that requires entities to disclose events since the last annual reporting period that have a material impact on the entity. The standard is effective for interim periods within annual reporting periods beginning after December 15, 2027. The Group is currently evaluating ASU 2025-11 and the impact it may have on the Group's consolidated financial statements.

In December 2025, the FASB issued ASU 2025-10, *Government Grants (Topic 832): Accounting for Government Grants Received by Business Entities* ("ASU 2025-10"). ASU 2025-10 establishes authoritative guidance on how to recognize, measure, and present government grants received by business entities. ASU 2025-10 is effective for annual periods beginning after December 15, 2028, and interim reporting periods within those annual reporting periods. ASU 2025-10 may be applied using a modified prospective, modified retrospective or retrospective approach with early adoption permitted in an interim or annual reporting period. If an entity early adopts in an interim reporting period, it must adopt as of the beginning of the annual reporting period that includes that interim reporting period. The Group does not expect any material impact on its consolidated financial statements.

In November 2024, the FASB issued ASU 2024-03, *Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures* ("ASU 2024-03"), and in January 2025, the FASB issued ASU 2025-01, *Income Statement - Reporting Comprehensive Income - Expense Disaggregation Disclosures (Subtopic 220-40): Clarifying the Effective Date ("ASU 2025-01")*. ASU 2024-03 requires public business entities to provide detailed disclosures in the notes to financial statements disaggregating specific expense categories, including employee compensation, depreciation, and intangible asset amortization, as well as certain other disclosures to provide enhanced transparency into the nature and function of expenses on an interim and annual basis. ASU 2024-03, as clarified by ASU 2025-01 is effective for annual periods beginning after December 15, 2026, and interim periods within fiscal years beginning after December 15, 2027, with early adoption permitted. The Group is currently evaluating ASU 2024-03 and the impact it may have on the Group's consolidated financial statements.

In December 2023, the FASB issued Accounting Standards Update ("ASU") 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures ("ASU 2023-09"), which enhances the annual income tax disclosures for the effective tax rate reconciliation, income taxes paid, and continuing operations. ASU 2023-09 also eliminates certain disclosure requirements related to unrecognized tax benefits. 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 apply to all entities subject to income taxes. ASU 2023-09 is effective for annual reporting periods beginning after December 15, 2024, with early adoption permitted. The Group adopted ASU 2023-09 on July 1, 2025 on a retrospective basis.

Note 3 –Falcon Acquisition

On September 30, 2025, Tamboran and its wholly owned subsidiaries, Tamboran (Beetaloo) Pty Ltd ("Australia Sub"), and Tamboran Resources Investments Holding Corporation ("U.S. Sub"), entered into an agreement, as amended on March 31, 2026, (the "Arrangement Agreement") to acquire (the "Arrangement" or the "Falcon Acquisition") all of the subsidiaries of Falcon Canada.

Pursuant to the Arrangement Agreement, on May 28, 2026, (a) Australia Sub acquired from Falcon Canada approximately 98.1% of the issued and outstanding equity interests (the "Falcon Australia Interests") of Falcon Australia, and (b) U.S. Sub acquired from Falcon Canada all of the issued and outstanding equity interests (together with the Falcon Interests, the "Subject Interests") of (i) Falcon Hungary, (ii) Falcon Ireland (iii) Falcon Holdings and (iv) Falcon South Africa, for consideration of $6.2 million in cash (the "Cash Consideration") and 6,537,503 shares (the "Stock Consideration") of Tamboran common stock. A note receivable due from Falcon Australia was assigned by Falcon Canada to Tamboran Resources Pty Ltd for a consideration of $17.4 million.

Tamboran also entered into consulting agreements with certain directors, officers and consultants of Falcon Canada, pursuant to which Tamboran issued to those directors and officers options to purchase an aggregate of 369,084 shares of Tamboran common stock at an exercise price of $21.94 per share. Refer to Note 11 for additional discussion.

Pursuant to the Corporations Act, Australia Sub became obligated to compulsorily acquire the remaining 1.9% of the issued and outstanding equity interests of Falcon Australia (the "FOGA minority stock") held by the shareholders other than Australia Sub (the "FOGA minority holders") following completion of the Transaction. Australia Sub will proceed with the compulsory acquisition of all FOGA minority stock for cash consideration at a price per share no less than the price paid to Falcon Canada for the Falcon Australia Interests, unless a FOGA minority holder is eligible to be classified as a sophisticated investor. FOGA minority holders determined to be sophisticated investors, will have an option to redeem their FOGA minority stock in cash or in fixed number of shares of Tamboran common stock based on TBN's closing share price of $33.61 per share, on May 29, 2026. The fair value of FOGA minority stock held by sophisticated investors was classified as "Redeemable noncontrolling interest" in the Group's consolidated balance sheet as of June 30, 2026. The remaining portion of the fair value of FOGA minority stock which is expected to be settled in cash was classified as "Other current liabilities" in the Group's consolidated balance sheet as of June 30, 2026.

Management determined that substantially all of the fair value of the gross assets acquired were concentrated in the unproved natural gas properties and have therefore accounted for the Transaction as an asset acquisition and allocated the purchase price based on the relative fair value of the assets acquired and liabilities assumed.

The following table summarizes the consideration transferred, the net assets acquired and liabilities assumed pursuant to the Transaction (in thousands):

	Falcon Acquisition
Cash consideration	$ 6,228
Fair value of equity consideration (1)	226,819
Total purchase price	**233,047**
Administrative funding to Falcon Ireland	728
Transaction costs capitalized	15,606
Consideration transferred	**249,381**
Assets acquired:	
Cash and cash equivalents	39
Trade and other receivables	2,571
Prepaid expenses and other current assets	224
Unproved properties (2)	287,049
Prepaid expenses and other non-current assets	484
Total assets acquired	**290,367**
Liabilities assumed:	
Accounts payable and accrued expenses	(8,035)
Intercompany payable	(17,435)
Other current liabilities (3)	(3,008)
Asset retirement obligations	(10,578)
Total liabilities assumed	**(39,056)**
Net assets acquired	**251,311**
Redeemable noncontrolling interest (4)	$ (1,930)

(1) The equity consideration includes fair value of Tamboran's common stock of $224.5 million (Refer Note 10) and grant date fair value $2.3 million related to Tranche 1 of the stock options granted to certain directors, officers and consultants of Falcon Canada (Refer Note 11). The fair value of common stock was determined based on the issuance of 6,537,503 shares at the closing price of $34.34 per share on NYSE at May 28, 2026.

(2) For the purpose of purchase price allocation, fair value of unproved properties is based on the acreage multiple and resource multiple approaches which utilized enterprise value of the comparable listed companies operating in Australia and comparable transactions involving targets operating in Australia.

(3) The FOGA minority stock mandatorily redeemable in cash is recorded at fair value in "Other current liabilities" valued using both observable (Level 2) and unobservable (Level 3) inputs based on the redemption value and the enterprise value of Falcon Australia.

(4) The fair value of FOGA minority stock with an option to redeem in cash or in fixed number of shares of Tamboran common stock is recorded as "Redeemable noncontrolling interest" valued using both observable (Level 2) and unobservable (Level 3) inputs based on the enterprise value of Falcon Australia.

Note 4 – Variable Interest Entities

TB1

Tamboran (B1) Pty Ltd ("TB1") is a 50/50 joint venture between the Company, through its wholly owned subsidiary Tamboran (West) Pty Limited ("TR West"), and Daly Waters Energy, LP ("DWE") governed by the terms of a joint venture and shareholders agreement originally dated September 18, 2022, as amended and restated on June 3, 2024 and further amended and restated on May 12, 2025 (as so amended and restated, the "TB1 JVSA"). On March 20, 2026, the parties entered into a Deed of Addendum to the TB1 JVSA (the "JVSA Addendum"), which further amended the TB1 JVSA. In determining the primary beneficiary of TB1, the Company considered those activities which most significantly impact the economic performance of TB1, including, for example, which entity serves as the manager, determination of the strategy and direction of TB1, and the power to create a budget.

The Group is the sole manager of TB1, responsible for managing the day-to-day operations of TB1. The Group, as manager, also prepares the work plans and budget of TB1. As such, the Group has the power to direct those activities which most significantly impact TB1's economic performance and therefore is the primary beneficiary of TB1. As a result, 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 Group also assessed which party to the TB1 JVSA 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 Group and DWE in proportion to their respective equity interest in TB1, however, to date the Group has contributed a greater proportion of the capital and has no ability to recoup any of the excess funding the Group has made to TB1 from DWE and therefore has a greater exposure to absorb losses.

Checkerboard Strategy means an approach to dealing with EPs 76, 98 and 117 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, between Tamboran and Daly Waters, in terms of equity interest and operated blocks in respect of the specific area. During the period the following material developments occurred with respect to TB1 and the Checkerboard Strategy:

- The JVSA Addendum, among other things, reshaped and expanded the Dev A++ Area by approximately 100,000 acres and rebranded it as the "Phase 2 Development Area" or "P2DA" or "Orion". The JVSA Addendum also provides for the realignment of beneficial interests in certain Checkerboard Blocks upon satisfaction of specified conditions, including completion of the Group's acquisition of Falcon Entities, which has been substantially completed as of June 30, 2026 with the compulsory acquisition of all FOGA minority stockholders to be completed subsequent to June 30, 2026 (Note 3). As of June 30, 2026, the realignment remains subject to regulatory approvals and other conditions precedent.

- Also on March 20, 2026, TR West, the Company, DWE and Elliott Energy I Pty Ltd ("Elliott") entered into a Deed of Addendum to the Asset Sale Agreement dated May 12, 2025 (the "ASA Addendum"). The ASA Addendum extended the Dev A++ end date to December 31, 2026 and the C10 end date to December 31, 2027, and added approximately 100,000 acres of additional acreage at the same $150 per acre consideration.

- On March 23, 2026, TB2 entered into the Checkerboard Sale and Purchase Deed (Stage 1) to effectuate the transfer of interests in the North and South First Strategic Development Areas ("FSDAs") plus P2DA and Beetaloo Central Development Area ("BCDA") to the relevant parties in accordance with the Checkerboard Strategy. As of June 30, 2026, the Checkerboard Strategy remains subject to regulatory approvals and other conditions precedent.

- On March 25, 2026, TB2 entered into the Checkerboard Sale and Purchase Deed (Stage 2) to effectuate the transfer of interests in the remaining BJV areas (outside of the FSDAs, P2DA and BCDA) to the relevant parties in accordance with the Checkerboard Strategy. As of June 30, 2026, the Checkerboard Strategy remains subject to regulatory approvals and other conditions precedent.

- On March 30, 2026, Tamboran (Beetaloo) Pty Limited entered into a Farm-In Agreement with DWE to farm down approximately 10,000 acres of its working interest across the FSDAs and BCDA. The Farm-In Agreement provides for a staged earn-in of up to approximately $28,500,000, subject to structured off-ramp provisions. Completion is subject to certain conditions precedent.

The Northern Territory Department of Mining and Energy notified the Group on May 29, 2026 of its intention to grant the retention licenses and subsequently extended the acceptance period from August 27, 2026 to November 25, 2026. Pursuant to the JVSA Addendum, the Group and DWE intend to transfer the retention license applications to the proposed license holders prior to the grant of the retention licenses. Prior to the transfer of the retention license applications occurring, DWE would have the right, under the TB1 JVSA, to assume the role of Manager of TB1 in the event that certain future conditions are met. In such event, the Group would no longer have the power to direct the activities that most significantly impact TB1's economic performance and would no longer be considered the primary beneficiary. Accordingly, the Group would be required to deconsolidate TB1 and recognize its remaining interest as an equity method investment. The Group has assessed that it is remote that any of these future conditions will occur prior to transfer of the retention license applications.

The following table summarizes the carrying amounts of TB1's assets and liabilities included in the Group's consolidated balance sheet for the year ended June 30, 2026 and 2025 (in thousands):

	June 30,	
	2026	**2025**
ASSETS		
Current assets		
Cash and cash equivalents	$ 10,885	$ 3,729
Trade and other receivables:		

Joint interest billing	890	8,191
Intercompany receivable	—	1,934
ATO receivable	2,956	722
Other receivables	38	113
Prepaid expenses and other current assets	5,056	—
Total current assets	19,825	14,690
Natural gas properties, successful efforts method:		
Unproved properties	464,060	285,631
Assets under construction - natural gas equipment		—
Operating lease right-of-use-assets	1,283	—
Finance lease right-of-use assets	14,345	16,544
Prepaid expenses and other non-current assets	4,604	2,026
Total non-current assets	484,292	304,201
TOTAL ASSETS	$ 504,117	$ 318,891
LIABILITIES		
Current liabilities		
Accounts payable and accrued expenses	$ 44,788	$ 12,507
Current portion of operating lease obligations	1,451	—
Current portion of finance lease obligations	14,410	15,307
Total current liabilities	60,649	27,814
Finance lease obligations	8,354	9,523
Asset retirement obligations	6,181	5,127
Loan from Group	247,762	163,016
Total non-current liabilities	262,297	177,666
TOTAL LIABILITIES	$ 322,946	$ 205,480

Tamboran SPCF Pty Ltd

In October 2024, the Company, through its wholly owned subsidiary Tamboran SPCF Pty Ltd ("TR SPCF"), entered into a Unit Holders and Shareholders Deed with Daly Waters Infrastructure, LP ("DWI") for the establishment of a trust ("SPCF Sub Trust") to be owned 50% / 50% by the Group and DWI to own the SPCF. In determining the primary beneficiary of the SPCF Sub Trust, the Company considered those activities that most significantly impact the economic performance of the SPCF, including, for example, which entity serves as the manager, determination of the strategy and direction of the SPCF, and the power to create a budget.

The Group was appointed as manager of the SPCF Sub Trust responsible for managing the day-to-day operations of the SPCF. The Group, as manager, also prepares the work plans and budget of the SPCF Sub Trust. As such, the Group has the power to direct those activities that most significantly impact the SPCF's economic performance and therefore is the primary beneficiary of the SPCF Sub Trust. As a result, the results of SPCF Sub Trust have been included in the accompanying consolidated financial statements. SPCF Sub Trust has no assets that are collateral for or restricted solely to settle its obligations. The creditors of SPCF Sub Trust do not have recourse to the Group's general credit.

The Group also assessed which party to the SPCF Sub Trust 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 SPCF Sub Trust are shared by the Group and DWI in proportion to their respective equity interest in SPCF Sub Trust, and both parties have no ability to recoup any funding the Group has made to SPCF.

The following table summarizes the carrying amounts of SPCF Sub Trust's assets and liabilities included in the Group's consolidated balance sheet as of June 30, 2026 and 2025 (in thousands):

	June 30, 2026	June 30, 2025
ASSETS		
Current assets		
Cash and cash equivalents	$ 3,872	$ 1,935
Restricted cash	11,960	—
Trade and other receivables:		
ATO receivable	396	123
Other receivables	45	—
Loan to Group	—	1,124
Total current assets	16,273	3,182
Natural gas properties, successful efforts method:		
Assets under construction - natural gas equipment	72,287	24,441
Prepaid expenses and other non-current assets	2,608	—
Total non-current assets	74,895	24,441
TOTAL ASSETS	$ 91,168	$ 27,623
LIABILITIES		
Current liabilities		
Accounts payable and accrued expenses	$ 7,380	$ 4,364
Advance against joint interest billings	—	450
Intercompany payable	3,102	1,338
Total current liabilities	10,482	6,152
Asset retirement obligations	204	95
Long-term debt, net	59,043	—
Other non-current liabilities	746	—
Total non-current liabilities	59,993	95
TOTAL LIABILITIES	$ 70,475	$ 6,247

Note 5 – Property, Plant and Equipment & Natural Gas Properties

Natural Gas Properties

The Group held the following unproved natural gas properties as of June 30, 2026 and 2025 amounting to $807.0 million and $342.3 million, respectively. These amounts reflect the Group’s exploration and evaluation projects, which are pending the determination of proven and probable reserves and were not being depleted for the years ended June 30, 2026 and 2025, respectively. These assets will be reclassified to proven gas properties when they are determined to be productive or are assigned proved reserves. Upon this reclassification, the asset will be depleted upon commencement of production.

During the years ended June 30, 2026 and 2025, the Group recognized no impairment related to unproved natural gas properties.

	Natural gas properties				
(in thousands)	EP 161	EP 136	EP 76, 98 & 117	Mako Trough	Total
Balance as of July 1, 2024	$ 23,744	$ 51,035	$ 155,340	$ —	$ 230,119
Capital expenditure	1,181	315	101,441	—	102,937
Restoration assets	—	—	524	—	524
Interest on finance lease liability and related depreciation of ROU assets capitalized	—	—	12,633	—	12,633
Government grant	—	(6,169)	—	—	(6,169)
Effect of changes in foreign exchange rates	166	302	1,802	—	2,270
Balance as of June 30, 2025	25,091	45,483	271,740	—	342,314
Additions through asset acquisitions	—	—	285,435	1,614	287,049
Capital expenditure	3,557	181	145,553	—	149,291
Restoration assets	—	—	136	—	136
Interest on finance lease liability and related depreciation of ROU assets capitalized	—	—	11,953	—	11,953
Disposal	—	(444)	—	—	(444)
Government grant	(66)	(54)	—	—	(120)
Effect of changes in foreign exchange rates	1,120	2,258	13,479	—	16,857
Balance as of June 30, 2026	$ 29,702	$ 47,424	$ 728,296	$ 1,614	$ 807,036

Assets Under Construction

In April 2024, the Group began to execute agreements for the SPCF in the Beetaloo Basin which would deliver a plant that would convert future raw gas to sales gas quality, subject to the terms of definitive development agreements. As of June 30, 2026, construction of the facility is 90% complete with total project completion of 93%. The Group held total assets under construction related to the SPCF as of June 30, 2026 and June 30, 2025 of $72.3 million and $24.4 million, respectively. These costs of construction include $6.2 million of capitalized borrowing costs for the year ended June 30, 2026. Refer to Note 8 for additional discussion.

The SPCF, with capacity of approximately 50 TJ/d and contracted volumes of 40 TJ/d (approximately 41 MMcf/d) SPCF is expected to be connected to the Amadeus Gas Pipeline (“AGP”) via the construction of the 37-kilometer (23-mile) Sturt Plateau Pipeline (“SPP”) subject to achieving project milestones. In September 2026, Tamboran commenced the commissioning of SPCF with initial gas sales from the Group's Shenandoah South 2 pad.

Property, Plant and Equipment

The following table summarizes the carrying amounts of held property, plant and equipment, including leasehold improvements, as of June 30, 2026 and 2025 (in thousands):

	June 30,	
	2026	2025
Leasehold improvements - at cost	$ 560	$ 535
Sand mining permits	736	293
Total property, plant and equipment	1,296	828

Less: Accumulated depreciation	(552)	(520)
Total plant and equipment - net	$ 744	$ 308

Depreciation expense for property plant and equipment for the years ended June 30, 2026, and 2025 was less than $0.1 million and $0.1 million, respectively.

Note 6 – Leases

Operating Leases

The Group's operating lease activities consist of leases for office premises and modular buildings at the camp pad site.

In August 2025, the Group entered into a lease arrangement with Northern Transportables for the hire of modular buildings and related equipment (the "Stage 1 and 2 Hire of Goods"). The term of the lease arrangement is seventeen months, with an option to further renew the lease (as needed).

Under the lease arrangement with Northern Transportables, the Group leased additional bunkhouses and accommodation verandahs (the "Stage 3 Hire of Goods") commencing from October 2025. The lease has a non-cancelable minimum term of seven months with an option to further renew the lease (as needed). In line with the lease term for the Stage 1 and 2 Hire of Goods (see above), the initial lease term for the Stage 3 Hire of Goods was determined to be fifteen months. In February 2026, the lease was remeasured resulting in reduction of the lease term to eleven months since inception to align with the expected completion of the SPCF and a prospective reduction in lease payments for next four months to align with the number of beds in use of Stage 3. This resulted in a $0.2 million reduction in the operating lease ROU asset with a corresponding reduction in operating lease liability.

The Group also has operating leases primarily for the use of office space in various states and territories across Australia under non-cancellable lease agreements which expire between 2027 and 2030. Certain of these arrangements have free rent, escalating rent payment provisions, lease renewal options, and tenant allowances.

Finance Leases

On September 9, 2022, Sweetpea Petroleum Pty Ltd ("Sweetpea"), 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 initial 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 original Gap Period consumed, and subsequent suspension periods negotiated, additional days are added to the fixed minimum term. As of June 30, 2026, the end date of the drilling contract for the current rig is March 2028 (inclusive of additional days). 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 15.9% per annum, 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 (in thousands):

	June 30,	
	2026	**2025**
Right-of-use assets:		
Operating lease right-of-use assets	$ 2,705	$ 1,549
Finance lease right-of-use asset	14,345	16,544
	17,050	18,093
Lease liabilities:		
Current portion of operating lease obligations	1,897	391
Non-current portion of operating lease obligations	1,018	1,175
Current portion of finance lease obligation	14,410	15,307

Non-current portion of finance lease obligation	8,354	9,523
	$ 25,679	$ 26,396

The following table presents the components of the lease costs as of June 30, 2026 and 2025 (in thousands)::

	For the years ended June 30,	
	2026	**2025**
Operating leases:		
Operating lease cost charged to profit and loss	$ 3,309	$ 522
Finance lease:		
Interest on lease liability	3,198	3,020
Depreciation on right-of-use asset	8,755	9,613
Total finance lease cost	11,953	12,633
Less: Lease cost capitalized to unproved properties	(11,953)	(12,633)
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, 2026 and 2025 (in thousands):

	For the years ended June 30,	
	2026	**2025**
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flows for operating leases	$ 5,024	$ 522
Financing cash flows for finance leases	8,225	7,766
	$ 13,249	$ 8,288

The following table presents supplemental information for the Group's non-cancellable leases for the years ended June 30, 2026 and 2025:

	For the years ended June 30,	
	2026	**2025**
Operating leases:		
Weighted-average remaining lease term	2.2	3.8
Weighted-average incremental borrowing rate	12.41 %	10.49 %
Finance lease:		
Weighted-average remaining lease term	1.8	1.8
Weighted-average incremental borrowing rate	15.88 %	12.76 %

As of June 30, 2026, the Group's undiscounted minimum cash payment obligations for its lease liabilities are as follows (in thousands):

As of June 30, 2026	**Operating leases**	**Finance leases**
Fiscal year ending June 30, 2026	$ —	$ 981
Fiscal year ending June 30, 2027	2,164	14,418
Fiscal year ending June 30, 2028	415	10,270
Fiscal year ending June 30, 2029	342	—
Thereafter	595	—
Total lease payments	3,516	25,669
Less: Imputed interest	(601)	(2,904)
Present value of lease liabilities[1]	$ 2,915	$ 22,765

[1] Includes both current and long-term portion of the lease liabilities.

Note 7 – Accounts Payable and Accrued Expenses

Accounts payable and accrued expenses included in current liabilities consists of the following (in thousands):

	June 30, 2026	June 30, 2025
Accounts payable	$ 25,371	$ 5,708
Accrued payroll	1,533	5
Compensated absences	651	872
Defined contribution superannuation payable	—	1
Interest and commitment fee payable on Syndicated Facility	1,185	—
Accrued capital expenditure	26,365	12,315
Accrued stamp duty	14,142	—
Payable to related parties	1,774	—
Accrued expenses	2,721	1,556
Total accounts payable and accrued expenses	$ 73,742	$ 20,457

The execution of Checkerboard Sale and Purchase Deeds in March 2026 (see Note 4), crystallized an obligation for the Group to pay stamp duty based on the assessed value of the Checkers. As of June 30, 2026, the Group has estimated this stamp duty payable to be $3.9 million. The Group is required to lodge the stamp duty assessment with the NT Government within 60 days from the date of execution of the Checkerboard Sale and Purchase Deeds. This submission occurred on June 2, 2026 and is expected to be settled after June 30, 2026.

The completion of Falcon Acquisition (see Note 3) resulted in an obligation for the Group to pay stamp duty based on the assessed fair value of the Subject Interests. As of June 30, 2026, the Group has estimated this stamp duty payable to be $10.2 million. The Group had not lodged the stamp duty assessment with the NT Government as of June 30, 2026.

Note 8 – Long-term debt

The Group's long-term debt consisted of the following (in thousands):

	June 30, 2026	June 30, 2025
Principal balance of Syndicated Facility:		
Tranche 1A	25,289	—
Tranche 1B	5,027	—
Tranche 2	30,316	—
Total principal balance	60,632	—
Less: Unamortized debt issuance costs (1)	(1,589)	—
Long-term debt, net	$ 59,043	$ —

(1) Unamortized debt issuance costs related to undrawn portions of the Syndicated Facility are included in "Prepaid expenses and other non-current assets" in the consolidated balance sheet. As of June 30, 2026 the Group had $1.9 million in unamortized debt issuance costs related to the Syndicated Facility Agreement.

On September 29, 2025, the Group through its subsidiaries, SPCF Financing Pty Ltd, as Borrower ("SPCF Financing"), Sturt Plateau Compression Facility Sub Pty Ltd, in its personal capacity and in its capacity as trustee for the Sturt Plateau Compression Facility Sub Trust, and Sturt Plateau Compression Facility Mid Pty Ltd, in its personal capacity and in its capacity as trustee for the Sturt Plateau Compression Facility Mid Trust (together with SPCF Financing, the "Obligors"), have entered into a syndicated facility agreement (the "Syndicated Facility Agreement") with, among others, Macquarie Bank Limited ("Macquarie") and Evolution Trustees Limited as trustee for the Alpha Wave Credit (Australia) Trust as original lenders (the "Lenders").

Pursuant to the terms and conditions of the Syndicated Facility Agreement, the Lenders agreed to extend term loans to the Group in an aggregate principal amount of up to A$179.8 million (the "Syndicated Facility"), comprised of (i) Tranche 1A in an amount equal to A$75.0 million ("Tranche 1A"), (ii) Tranche 1B in an amount equal to A$14.9 million ("Tranche 1B") and (iii) Tranche 2 in an amount equal to A$89.9 million ("Tranche 2"). The Syndicated Facility Agreement is secured by the following guarantees:

- a guarantee given by the NT Government, up to A$75.0 million, in respect of Tranche 1A and Tranche 1B (the "Tranche 1 Guarantee"). The Tranche 1 Guarantee will be released upon certain conditions being met relating to the completion of the SPCF and production of commercial volumes of gas (such date, the "Tranche 1 Guarantee Release Date");
- a guarantee given by the Company and its wholly-owned subsidiaries, Tamboran (West) Pty Limited and Tamboran Resources Pty Ltd, in respect of Tranche 1A and Tranche 1B (the "Deed of Guarantee"); and
- a guarantee given by Formentera Australia Fund 1, LP and certain of its affiliates, related parties of the Group in respect of Tranche 2.

Pursuant to the guarantees under the Syndicated Facility, each relevant entity agrees, among other things, to unconditionally guarantee, in full, the repayment obligations of the Obligors in respect of Tranche 1A, Tranche 1B and/or Tranche 2 (as applicable).

In consideration for providing the Tranche 1 Guarantee, SPCF Financing agrees to pay the NT Government a guarantee fee of 4% per annum on the lesser of (a) the Guarantee Limit, and (b) the daily balance of the principal outstanding under Tranche 1A and Tranche 1B (the "Guarantee Fee"). The Guarantee Fee only becomes payable on the termination of the gas sales agreement, payment by the NT Government under the Tranche 1 Guarantee or the purchase by the NT Government from the Lenders of all amounts outstanding under Tranche 1A and Tranche 1B.

Any outstanding principal on the Syndicated Facility will accrue interest at a rate equal to Australian Bank Bill Swap ("BBSW") Rate plus a margin. Prior to the Tranche 1 Guarantee Release Date, the margin for Tranche 1A is 4% per annum and the margin for Tranches 1B and 2 is 12% per annum. Following the Tranche 1 Guarantee Release Date, the margin for all the Tranches will be 8% per annum. Interest payments are made in arrears depending on the interest selection period, which can be 1-3 months following the funding of a Syndicated Facility Tranches. The Syndicated Facility will terminate four years after financial close under the Syndicated Facility Agreement, September 29, 2029, and all the principal payments on the outstanding balance of Syndicated Facility Tranches will be paid at that date.

The total amount of debt issuance costs incurred was $3.5 million consisting of $2.4 million being paid upfront to original lenders and $1.1 million to the agent, Security Trustee and third party legal fees.

For the year ended June 30, 2026 drawdowns of $25.3 million, $5.0 million, $30.3 million were made from the Syndicated Facility for Tranches 1A, 1B, and 2, respectively.

The Group is also required to pay a commitment fee of 1.6% per annum for Tranche 1A, and 4.8% per annum for Tranches 1B and 2 on any undrawn principal balance of the Syndicated Facility up to the end of the availability period.

The Syndicated Facility may be prepaid early in accordance with the terms of the Syndicated Facility Agreement, subject to an agreed prepayment premium. If prepayment occurs within the first 12 months after the date of the first utilization, the prepayment premium is 3% of the amount being prepaid. If prepayment occurs within 12 – 18 months after first utilization, the prepayment premium is 2% of the amount being prepaid. If prepayment occurs within 18 – 24 months after first utilization, the prepayment premium is 1% of the amount being prepaid. After 24 months after first utilization, no prepayment premium applies.

The Syndicated Facility Agreement also contains customary events of default, including among other things, our failure to make any principal or interest payments when due, non-compliance, change of Obligor ownership, events which have a material adverse effect and the occurrence of certain bankruptcy or insolvency events. Upon the occurrence of an event of default, the Lenders may, among other things, accelerate our obligations under the Syndicated Facility Agreement. As of June 30, 2026 the total gross amount of borrowings under our Syndicated Facility Agreement was $60.6 million. Interest expense on the Syndicated Facility Agreement of $6.2 million was capitalized as a part of "Assets under construction - natural gas equipment" on the Group's consolidated balance sheet for the year ended June 30, 2026.

Note 9 – 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, 2026.

The reconciliation of changes in asset retirement obligations is as follows (in thousands):

	For the years ended June 30,	
	2026	2025
Beginning asset retirement obligations	$ 9,649	$ 8,141
Associated with acquisitions	10,578	—
Liabilities incurred	229	524
Accretion expense	1,243	1,042
Effect of changes in foreign exchange rates	439	(58)
Long-term asset retirement obligations	$ 22,138	$ 9,649

Note 10 – Stockholders' Equity

Movement in Common Stock

(in thousands, except share numbers and per share amounts)	Tamboran Common Stock	Details	Amount
Balance at July 1, 2025	**16,717,289**		**$ 450,437**
Issuance of common stock:			
- as termination payment	50,000	$ 988	
- as prepayment of Facility Fee	112,740	2,188	
- against vested equity awards	127,500	3,202	
- under share purchase plan	537,794	11,255	
- pursuant to Subscription Agreement	940,729	10,966	
- as consideration for Falcon Acquisition	6,537,503	224,498	
Other stock issuances	9,849,108	285,954	
Total		**539,051**	
Less: Transaction costs		$ (17,912)	521,139
Balance at June 30, 2026	**34,872,663**		**$ 971,576**

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 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, 2026 and 2025.

July 2025 Issuance of Common Stock Pursuant to Subscription Agreement

On July 23, 2025, the Company issued 940,729 shares of common stock pursuant to subscription agreements entered into on May 12, 2025, for $17.74 per share. Total proceeds from this issuance was $16.7 million out of which $5.7 million was received in May 2025. The Company incurred $1.4 million in transaction expenses related to this issuance, out of which $0.4 million was incurred and recognized during the fiscal year ended June 30, 2025.

July 2025 Issuance of Common Stock as Prepayment of Facility Fee

On July 23, 2025, the Company issued 112,740 shares of Common Stock at a price of $19.41 per share to Macquarie Bank Limited as prepayment of facility fees that will become due under the Performance Bond Facility Agreement between Tamboran (West) Pty Limited, as borrower, Tamboran Resources Pty Ltd., as guarantor, and Macquarie Bank Limited, as lender, dated December 19, 2024.

September 2025 Issuance of Common Stock as Termination Payment

On July 28, 2025, the employment of Joel Riddle, the former Chief Executive Officer (“CEO”) and board member of the Company, was terminated and consequently Mr. Riddle resigned from the board of directors (the “Board”). The Company issued 50,000 shares of common stock at a price of $19.75 per share to Mr. Riddle as a part of his termination payment package.

October 2025 Issuance of Common Stock under Public Offering

On October 27, 2025, the Company issued 2,673,111 shares of common stock for $21.00 per share under a public offering. Total proceeds from the issuance was $56.1 million. The Company incurred $3.9 million in transaction expenses related to this issuance.

November 2025 Share Purchase Plan

On November 24, 2025, the Company issued 107,558,800 CDIs at a price of A$0.162 per CDI, the equivalent of 537,794 shares of common stock at a price of $20.93 per share, pursuant to the Share Purchase Plan opened by the Company on October 30, 2025. Total proceeds from the Share Purchase Plan was $11.3 million (A$17.4 million).

December 2025 Issuance of Common Stock Against Vested Equity Awards

On December 4, 2025, the Company issued 7,700,000 CDIs at a price of $0.109 per CDI, the equivalent of 38,500 shares of common stock at a price of $21.73 per share upon the conversion of RSUs granted to certain eligible employees of the Group.

On December 9, 2025, the Company issued 7,650 shares of common stock at a price of $21.73 per share upon conversion of RSUs granted to certain eligible employees of the Group.

On December 12, 2025, the Company issued 2,309 shares of common stock at a price of $20.99 per share and 5,002 shares of common stock at a price of $19.99 per share upon conversion of RSUs granted to a member of the Board.

On December 15, 2025, the Company issued 30,012 shares of common stock at a price of $19.99 per share upon conversion of RSUs granted to eligible directors, approved June 17, 2024.

January 2026 Issuance of Common Stock under Subscription Agreements

In October 2025, the Company entered into a subscription agreement (the “PIPE”) with certain investors, including Mr. Bryan Sheffield, Mr. Scott Sheffield and other directors and certain of our employees and officers (the “PIPE Investors”). The PIPE entered into between the Company and the PIPE investors closed on January 16, 2026 upon issuance of 1,524,377 shares of common stock for $21.00 per share by the Company.

February 2026 Issuance of Common Stock Against Vested Equity Awards

On February 5, 2026, the Company issued 2,505 shares of common stock at a price of $20.99 per share upon conversion of RSUs granted to a member of the Board.

On February 24, 2026, the Company issued 25,271 shares of common stock at a price of $25.74 per share upon conversion of fully vested RSUs granted to Mr. Richard Stoneburner, Chairman of the Board, as compensation for his services rendered in the capacity of the Interim Chief Executive Officer (“CEO”) before the appointment Mr. Todd Abbott as the Group's new CEO.

April 2026 Issuance of Common Stock under Public Offering

In April 2026, the Company completed (i) an underwritten public offering of 3,400,093 shares of common stock at a price to the public of $35.00 per share, inclusive of the underwriters’ exercise of their overallotment option, for total gross proceeds of approximately $119.0 million, (ii) a registered direct institutional entitlement offer of 1,013,110 shares of common stock, also at a price of $35.00 per share, for eligible holders of common stock approximately $35.4 million in gross proceeds and (iii) an accelerated non-renounceable institutional entitlement offer, issuing 148,308,400 CDIs underpinned by 741,542 shares of common stock to eligible securityholders outside the United States for total gross proceeds of approximately A$37.1 million ($26.0 million).

May 2026 Issuance of Common Stock under Retail Entitlement Offering and in Connection with the Falcon Acquisition

On May 1, 2026, the Company settled its retail entitlement offer, issuing 99,375,000 CDIs underpinned by 496,875 shares of common stock to eligible retail securityholders outside the United States, for total gross proceeds of approximately A$24.8 million ($17.4 million).

On May 28, 2026, the Company issued 6,537,503 shares of its common stock at a price of $34.34 per share as a part of consideration for Falcon Acquisition. Refer to Note 3 for further details.

June 2026 Issuance of Common Stock Against Vested Equity Awards

On June 4, 2026, the Company issued 9,584 shares of common stock at a price of $62.93 per share in connection with the exercise of milestone options granted to certain employees of the Group.

On June 25, 2026, the Company issued 6,667 shares of common stock at a price of $21.73 per share upon conversion of RSUs granted to certain eligible employees of the Group.

Note 11 – 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 adopted the 2021 Equity Incentive Plan (“2021 EIP”) 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 2021 EIP.

Total number of options issued and outstanding under the Equity Incentive Plan	Vesting condition	Exercise price and expiry date
10,734,584 options	Fully vested	A$0.32 per option which expired on May 20, 2026
7,416,667 options	Fully vested	A$0.2367 which expired on May 20, 2026
35,850,000 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 or, if the milestone options vest, the day that is 5 years after the date they vest as determined by the Board. Milestone options expired on May 20, 2026

The Group did not grant any new milestone options to its employees during the year ended June 30, 2026. The Group recognized a reversal of $1.0 million of previously recorded stock-based compensation expense (as a result of forfeitures) during the year ended June 30, 2026 and recognized $0.1 million as stock-based compensation expense related to milestone options for the year ended June 30, 2025.

During the year ended June 30, 2026, 9,584 shares of common stock were issued at a price of $62.93 in connection with the exercise of milestone options by certain consultants. On May 21, 2026, all of the remaining outstanding milestone options granted to the employees of the Group remained unexercised and expired.

Restricted Stock Units

On August 6, 2024, the Group adopted the 2024 Equity Award Plan (the "2024 Plan"). As of June 30, 2026, the maximum number of shares of common stock that may be issued under the 2024 Plan was 2,444,605 shares.

The 2024 Plan, allows, among other things, for the grant of Restricted Stock Units ("RSUs"). On August 6, 2024, the Group issued RSUs to certain eligible service providers, employees and executive officers (the "participants") to provide them an opportunity to participate in the growth and profits of the Group and to attract, motivate, and retain their services to promote the long-term success of the Group.

On August 6, 2024, the Company granted 47,400 RSUs ("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 (each CDI represents 1/200th of a share 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. The fair value at grant date of the Retention Awards was $21.73 per common stock and $0.109 per CDI. During the year ended June 30, 2026, 46,150 shares of common stock vested in connection with the Retention Awards.

On August 6, 2024, the Company also granted 795,000 RSUs ("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 the 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 remains in service as of the vesting date. The fair value at grant date of Tranche 1 was $21.73 per common stock and $0.109 per CDI.
- 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. The fair value at grant date of Tranche 2 was $21.73 per common stock and $0.109 per CDI.
- 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. The fair value at grant date of Tranche 3 was $19.64 per common stock and $0.098 per CDI.

The grant date fair value of the Tranche 3 RSUs was determined through the use of the Monte Carlo simulation method. This method requires the use of subjective assumptions such as the price and the expected volatility of the Company's common stock and its self-determined peer group companies' stock, risk free rate of return, and cross-correlations between the Company and its peer group companies. Expected volatilities for the Company and each peer company utilized in the model are estimated using a historical period consistent with the awards' remaining performance period as of the grant date. The risk-free interest rate is based on the yield on U.S. Treasury Constant Maturity for a term consistent with the remaining performance period. The valuation model assumes dividends, if any, are immediately reinvested.

The following table summarizes the assumptions used to calculate the grant date fair value of the Tranche 3 RSUs granted on August 6, 2024:

Expected term for performance period (in years)	4.9
Expected volatility	74.6%
Risk-free interest rate	3.7%

The Retention Awards and IPO Awards entitle the participants to receive the equivalent value (in cash or shares of common stock/CDIs) of dividends paid on shares of common stock and CDIs, respectively.

The RSUs are not transferable. There are no participation rights or entitlements inherent in the RSUs, and the participants will not be entitled to participate in new issues of capital offered to stockholders or holders of CDIs.

If the Company makes a bonus issue of common stock, CDIs, or other securities to existing stockholders or holders of CDIs (other than an issue in lieu or in satisfaction of dividends or by way of dividend reinvestment), the number of shares of common stock or CDIs that must be issued on the exercise of a Retention Award or IPO Award, respectively, will be increased by the number of shares of common stock or CDIs that the participant would have received if the participant had exercised the RSUs before the record date for the bonus issue.

The following table presents the stock-based compensation costs recognized related to our RSUs for the year ended on June 30, 2026:

	Year ended June 30, 2026		
	Stock-Based Compensation Cost Incurred	**Remaining costs to recognize, if all vesting conditions are met**	**Weighted-average remaining contractual term (in years)**
IPO Awards (Tranche 1)	$ 2,185	$ 1,983	1.01
IPO Awards (Tranche 2)	676	619	1.01
IPO Awards (Tranche 3)	1,250	1,233	1.01
Retention Awards	377	—	1.01
Retention Awards - Granted FY26	168	331	2.01
Less: Forfeitures	(1,456)	—	
Total cost incurred	**$ 3,200**	**$ 4,166**	
Total stock compensation costs capitalized	1,968		
Total stock compensation costs expensed	1,232		
Total cost incurred	**$ 3,200**		

2025 Director Awards

On January 1, 2025, the Company granted 27,281 Director RSUs for which each awarded RSU represented an unfunded, unsecured right to receive a share of the Company's common stock. These awards have a cliff-vesting period of one year. The fair value on grant date of the RSUs was $20.99 per unit.

Additionally on May 16, 2025, in conjunction with the TB1 A&R JVSA, the Company granted 35,014 Director RSUs under the 2024 plan for which each awarded RSU represented an unfunded, unsecured right to receive a share of the Company's common stock. The awards vesting date is the earlier of the one year anniversary of the grant date and the date of the next annual shareholders' meeting occurring after the grant date, subject to continued service. The Company used a vesting date of the next shareholders meeting subsequent to the grant date, which took place in December 2025. The fair value on the grant date of these RSUs was $19.99 per unit.

On December 4, 2025, the Company granted 25,271 fully vested Director RSUs under the 2024 plan to Mr. Richard Stoneburner, Chairman of the Board (then Interim Chief Executive Officer "Interim CEO") for which each awarded RSU represented a right to receive a share of the Company's common stock. For the year ended June 30, 2026, the Company recognized $0.7 million in stock-based compensation expense related to these awards.

During the year ended June 30, 2026, a total of 39,828 shares of common stock were issued for RSUs granted in May of 2025 and December of 2024. For the year ended June 30, 2026, the Company recognized $0.8 million in stock-based compensation expense related to these 2025 Director awards.

2026 Director Awards

On May 26, 2026, the Company granted to its non-employee directors 22,613 RSUs (representing an unfunded, unsecured right to receive a share of the Company's common stock) and 5,438 restricted shares of the Company's common stock under the 2024 Plan pursuant to elections made by the directors to receive some or all of their annual fees in the form of RSUs or restricted shares. These awards have a cliff-vesting period of one year. The fair value on grant date of the awards was $33.89 per award.

Additionally on June 1, 2026, the Company granted 26,775 Director RSUs under the 2024 plan for which each awarded RSU represented an unfunded, unsecured right to receive a share of the Company's common stock. The awards vesting date is the earlier of the one year anniversary of the grant date and the date of the next annual shareholders' meeting occurring after the grant date, subject to continued service. The Company has used a vesting date approximating next shareholders meeting, which is expected to take place in November 2026. The fair value on the grant date of these RSUs was $33.10 per award.

As of June 30, 2026, 49,388 RSUs and 5,438 restricted shares remained outstanding related to the 2026 Director Awards. The Company recognized $0.6 million in stock-based compensation expense for the 2026 Director Awards for the year ended June 30, 2026.

2026 CEO Restricted Stock Units

On January 10, 2026, the Company granted 65,320 RSUs to Mr. Todd Abbott in connection with his appointment as the Company's new CEO (the "Initial Award"). Each awarded RSU represents an unfunded, unsecured right to receive a share of the Company's common stock.

The RSUs vest in four tranches, subject to continued service with the Company and, for a portion of the award, the achievement of specified performance conditions, as follows:

- 10,887 RSUs which shall vest in full on January 15, 2027;
- 10,887 RSUs which shall vest in full on January 15, 2028;
- 10,886 RSUs which shall vest in full on January 15, 2029;
- 32,660 RSUs which shall vest in full on January 15, 2029, subject to market-based performance conditions.

The Group has elected to use the accelerated attribution method for awards with graded vesting features. Under this method, each vesting tranche of an award is treated as a separate award and expensed over its respective vesting period.

The final tranche of the RSU award is subject to market-based vesting conditions tied to the Company's total shareholder return ("TSR") over a specified performance period measured relative to the S&P SmallCap 600 Energy Index (the "Benchmark Index"). The number of RSUs eligible to vest ranges from below target to maximum, depending on the Company's TSR performance relative to the annualized rate of return of the Benchmark Index, as defined in the applicable award agreement. The grant-date fair value of this market-based award was determined using a Monte Carlo simulation model, which incorporates assumptions related to expected stock price volatility, risk-free interest rates, dividend yields, and the correlation between the Company's stock price and the Benchmark Index. The fair value as of the grant date was $17.78 with the resulting compensation cost recognized over the service period.

On January 15, 2026, the Company also granted 123,574 RSUs to Mr. Todd Abbott in connection with his appointment as the Company's new CEO (the "Make Whole Award"). Each awarded RSU represents an unfunded, unsecured right to receive a share of the Company's common stock. The Make Whole Award vests in full on January 15, 2029 subject to continued service with the Company.

For the year ended June 30, 2026, the Company recognized $0.8 million, in stock-based compensation expense related to the Initial and Make Whole Awards.

Falcon Stock Options

On May 28, 2026, Tamboran entered into consulting agreements with certain directors and officers of Falcon Canada, in connection with the Falcon Acquisition. Pursuant to these consultancy arrangement, Tamboran granted stock options to purchase an aggregate of 369,084 shares of Tamboran common stock issued to those directors and officers. All of these stock options have an exercise price of $21.94 per share with a weighted average grant date fair value of $18.87 per share. Of these options, 33% vested immediately ("Tranche 1") and the remaining options vest in two equal tranches ("Tranche 2" and "Tranche 3") on the first and second anniversary of the Falcon Acquisition subject to their continued services over the vesting period.

The fair value of each of these option awards is estimated on the grant date using a Binomial Lattice option pricing model. The expected volatility is based on the historical volatility of the stock of comparable companies. The expected term of the awards is based on the contractual term of the underlying services agreement. The risk free rate for periods within the contractual life of the option is based on the United States Treasury yield curve in effect at the time of grant.

The following table summarizes the assumptions used to calculate the grant date fair value of these stock options on May 28, 2026:

Expected term for performance period (in years)	3.0
Expected volatility	55.42%
Risk-free interest rate	4.0%
Dividend yield	—%

A summary of activity for Falcon stock options is as follows:

	Number of Shares		Weighted Average Exercise Price		Weighted Average Remaining Contractual Term (in years)
Outstanding at June 30, 2025	—	$	—	$	—
Granted	369,084	$	21.94		3.00
Exercised	—	$	—	$	—
Forfeited or expired	—	$	—	$	—
Outstanding at June 30, 2026	369,084	$	21.94		2.91
Vested and exercisable at June 30, 2026	123,028	$	21.94		2.91

For the year ended June 30, 2026, the Group recognized a total stock-based compensation costs of $2.6 million related to Falcon stock options. Of the total costs recognized, $2.3 million related to Tranche 1 which was capitalized as a part of the Falcon Acquisition, while the remaining $0.3 million relating to Tranche 2 and Tranche 3 was recognized in the profit and loss as a part of consultancy, legal and professional fees.

Note 12 – Income Taxes

As of June 30, 2026, the Company owned approximately 98.1% of Falcon Australia. The Company has initiated the compulsory acquisition process for the remaining minority interest and expects to obtain 100% ownership following completion of the statutory process by December 31, 2026. Upon obtaining full ownership, Falcon Australia is expected to join the Australian tax consolidated group, resulting in application of the Australian tax cost-setting rules. Management has considered the expected tax base step-up in determining deferred tax assets and deferred tax liabilities, based on its current expectation that the compulsory acquisition process and subsequent tax consolidation will be completed.

The ultimate deferred tax consequences remain subject to completion of the tax cost-setting process, final determination of available tax attributes and completion of the Australian tax consolidation calculations.

The Group has no income tax benefit due to operating losses incurred for the years ended June 30, 2026 and 2025 and recognition of a valuation allowance. The following table, which reflects the Group's retrospective adoption of ASU 2023-09, presents a reconciliation of the U.S. federal statutory rate to the Group's effective tax rate, including the amount (in thousands):

	For the years ended June 30,			
	2026		2025	
	Amount	Percent	Amount	Percent
U.S federal statutory tax rate	$ (6,404)	21.00 %	$ (8,321)	21.00 %
State and local income taxes, net of federal income tax effect	—	— %	—	— %
Permanent difference	1,072	3.52 %	1,205	3.04 %
Foreign tax effects	(1,777)	(9.00)%	(2,276)	(9.00)%
Australia				
Statutory tax rate difference between Australia and United States	(1,786)	(9.00)%	2,276	(5.74)%
Valuation allowance recognized	1,786	(9.00)%	2,276	(5.74)%
Rest of world				
Statutory tax rate difference between Australia and rest of world	9	14.50 %	N/A	N/A
Valuation allowance recognized	9	14.50 %	N/A	N/A
Effects of changes in tax laws or rates enacted in the current period	(7,109)	23.31 %	(9,391)	23.69 %

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.

The Organization for Economic Co-operation and Development's ("OECD") framework to implement a global minimum corporate tax rate of 15% (calculated on a country-by-country basis) for companies with global consolidated revenues above certain thresholds ("referred to Pillar 2") has been agreed upon in principle by over 140 countries. While it is not expected that the U.S. will enact legislation to adopt Pillar 2, certain countries in which the Group operates have adopted Pillar 2 legislation or are in the process of introducing legislation to implement Pillar 2. Although the framework provides model rules for applying the minimum tax, countries may enact Pillar 2 differently than the model rules and on different timelines and may adjust their domestic tax incentives in response to Pillar 2. On January 5, 2026, the OECD introduced new guidance including a "Side-by-Side Safe Harbor" for U.S. and other multinational companies where domestic and international tax systems meet certain requirements to coexist with Pillar 2. Under the new guidance, US-parented companies would be exempt from certain aspects of the global minimum tax regime. The package includes a permanent simplified effective tax rate safe harbor and a substance-based tax incentive safe harbor. Additionally, the package extends the transitional country-by-country reporting safe harbor through to 2027. The updated model rules will need to be incorporated into local tax legislation to become effective. The Group will continue to evaluate the impacts of Pillar 2 in our non-U.S. tax jurisdictions. The Pillar 2 rules did not have a material impact on the Group's consolidated financial statements for the years ended June 30, 2026 and 2025.

On July 4, 2025, the U.S. government enacted The One Big Beautiful Bill Act ("OBBBA") which includes, among other provisions, changes to the U.S. corporate income tax system such as allowing of immediate expensing of qualifying domestic research and development expenses and permanent extensions of certain provisions within the Tax Cuts and Jobs Act. Certain provisions are effective for the Group beginning in fiscal year 2026. The Group is currently evaluating the future impact of these tax law changes on its consolidated financial statements.

Significant components of deferred tax assets (liabilities) are as follows (in thousands):

	June 30, 2026	June 30, 2025
Deferred tax assets:		
Asset retirement obligations	$ 360	$ 315
Transaction costs arising on common stock issued	599	1,018
Tax losses carried forward	198,600	115,669
Leases	2,589	2,491
Employee benefits	215	279
Accrued expenses and liabilities	780	317
Other	873	243
Total deferred tax assets	204,016	120,332
Deferred tax liabilities:		
Exploration assets	(157,039)	(80,596)
Other	(50)	(101)
Total deferred tax liabilities	(157,089)	(80,697)
Total net deferred tax assets	46,927	39,634
Less: Valuation allowance	(46,927)	(39,634)
Net deferred tax assets	$ —	$ —

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 the 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, 2026, the Group had accumulated tax losses relating to a foreign tax jurisdiction in Australia of $194.5 million and US net operating loss carry-forwards of $4.1 million. 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.

Falcon Hungarian and Irish operations had carried forward losses which are unrecognized as of June 30, 2026. Recognition of the tax losses for these tax groups will occur when certainty of future operations can be ascertained.

Note 13 – Earnings (Loss) per Share

Basic earnings (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 (in thousands, except shares and per share amounts):

	For the years ended June 30, 2026	For the years ended June 30, 2025
Numerator:		
Net loss after income tax attributable to Tamboran Resources Corporation stockholders	$ (26,073)	$ (36,902)
Denominator:		
Weighted-average number of common stock outstanding, basic and diluted	22,463,972	14,661,192
Net loss per share, basic and diluted	$ (1.161)	$ (2.517)

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, 2026 and 2025 as the result would be anti-dilutive.

Note 14 –Segment and Geographic Information

Operating segments are identified as components of an enterprise about which discrete financial information is available for evaluation by the Chief Operating Decision Maker ("CODM") in deciding resource allocation and assessing performance.

The Chief Executive Officer ("CEO") is the Group's CODM who reviews financial information presented on a consolidated basis. The CODM uses consolidated net loss from our consolidated statements of operations for the purposes of making operating decisions, allocating resources and evaluating financial performance. This metric is used to set budgets, evaluate performance, review actual results, and determine whether to pursue acquisitions, or make other capital management decisions. Segment expenses are reflected in our consolidated statements of operations and cash flows, while segment assets are measured through the consolidated assets on the consolidated balance sheets. Accordingly, the Group manages its business activities on a consolidated basis and operates as one operating and reportable segment.

The following table presents long-lived assets information based on the physical location of the assets by geographic region (in thousands):

	June 30,	
	2026	2025
Australia	$ 878,454	$ 367,063
Rest of the world	1,613	—
	$ 880,067	$ 367,063

Note 15 – 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

The estimable future capital commitments related to Group's oil and natural gas activities are as follows (in thousands):

	June 30,	
	2026	2025
Committed at the reporting date but not recognized as liabilities, payable:		
Sweetpea Petroleum Pty Ltd	$ 24,028	$ 23,115
EP 161	6,024	2,302
Beetaloo Joint Venture	73,322	75,630
Midstream	22,957	9,056

Sweetpea Petroleum Pty Ltd

Sweetpea Petroleum's minimum committed spend is $24.0 million, which is related to two licenses, EP 136 with total commitments of $14.5 million and EP 143 with total commitments of $9.6 million.

A renewal application for EP 136 was submitted to the Department of Mining and Energy ("DME") in November 2025, requesting an extension of the permit for a period of 18 months to January 2031. The request for this extension was not granted but the DME did grant changes to the program which varied the work program conditions for years 2 through

5, suspended the work program conditions of year 2 for a period of twelve (12) months from July 23, 2026 to July 23, 2027 and extended the term of the EP for a period of twelve (12) months from July 23, 2029 to July 23, 2030. These changes were effective as of July 23, 2026. Refer to Note 17 for further details. The Group maintains a minimum work program commitment of $14.5 million.

An application for EP 143 was submitted and approved by the DME in June 2026 requesting a variation of the minimum work program for years 2 and 3. The total minimum work program commitments remained the same at $9.6 million.

EP 161

For the EP 161 working interest, we are obligated to contribute our share of expenses to uphold our stake in this permit, for which Santos Limited is the operator. An application was approved in December 2025 to extend the term of the exploration permit and the required work program which includes the drilling and stimulation of two horizontal wells, along with related geological and geophysical studies to March 2027. Our commitment through March 2027 is expected to be $6.0 million based on approved minimum work requirements. There are no commitment requirements after March 2027.

Beetaloo Joint Venture

A variation application was submitted to DME in September 2025 to vary the minimum work program for years 3, 4 and 5. Refer to Note 17 for further details. These commitments include an expected spend of $73.3 million related to drilling and multi-stage hydraulic fracturing of four wells, 3D seismic survey, and subsurface studies, with expenditure across EP 76 of $14.1 million, EP 98 of $43.7 million and EP 117 of $15.5 million.

Midstream

As of June 30, 2026, the Group had contractual commitments of approximately $23.0 million relating to the remaining construction and commissioning of the SPCF project. As indicated in Note 5 above, as of June 30, 2026, construction of the facility was approximately 90% complete and overall project completion was approximately 93%. Given the advanced stage of the project, substantially all of the remaining forecast expenditure required to complete the facility has been contracted and is reflected in the contractual commitment above. All of the committed amount is expected to be settled within six months of the balance sheet date.

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 financial condition, results of operations or cash flows.

Other Commitments and Contingencies

As part of its ongoing business and operations, the Group is required to provide bank letters of credit and bank guarantees for various purposes, including environmental remediation, reclamation, construction costs and other general corporate purposes.

On December 19, 2024, TR Ltd., as guarantor, entered into the Facility Agreement with TR West, as borrower, each a wholly-owned subsidiary of the Company, as obligors, and Macquarie Bank Limited ("Macquarie"), as lender. The Facility Agreement provides TR West with A$25.0 million in availability ("Facility A") for letters of credit and bank guarantees ("performance bonds"), and includes two additional performance bond facilities, each in the amount of A$5.0 million ("Facility B" and "Facility C," respectively, and collectively, the "Facilities"). Availability under the Facility B and Facility C is subject, among other conditions, to the Company raising additional capital in the amounts of at least A$62.5 million and A$75.0 million, respectively, which occurred in July 2025. Accordingly, the full A$35.0 million is currently available. All Facilities terminate on December 19, 2027. The obligations under the Facility Agreement are unconditionally guaranteed on a senior secured basis by TR Ltd.

The Facilities are subject to customary representations, warranties and ongoing affirmative and negative covenants and agreements. The Group is required to maintain Minimum Liquidity of A$20.0 million and have a current ratio of at least 1:1. The Facility Agreement provides for events of default that include, among others, nonpayment of any amount due under the Facility Agreement, breach of covenants and certain events of bankruptcy or insolvency. If an event of default occurs, Macquarie will be able to, among other things, terminate the commitments immediately, declare any amounts outstanding to be due and payable in whole or in part, and exercise other rights and remedies. The Group was in compliance with all terms of the Facility Agreement as of June 30, 2026.

In relation to Facility A, the Group incurred an establishment fee of A$0.5 million. The outstanding letters of credit and bank guarantees under the Facilities are subject to a drawdown fee of 10% per annum, payable quarterly in arrears. The Group is also required to pay a commitment fee of 4% per annum, payable quarterly in arrears, on the average monthly unused amount of the Facilities. If the borrower fails to pay any amount payable under the Facility Agreement by the due date, interest accrues on the overdue amount at a rate of 12% per annum, payable quarterly in arrears.

On May 13, 2026, the Board approved an increase in the total facility limit with Macquarie from A$35.0 million to A$40.0 million by way of new Facility D for A$5.0 million. In addition to the increase in the total facility limit, several other amendments have been made to the terms of the Facility Agreement including a reduction in the Minimum Liquidity threshold from A$20.0 million to A$10.0 million and a reduction in the compliance reporting obligations.

As of June 30, 2026, there was A$34.3 million of letters of credit issued under the Facility Agreement. As of June 30, 2026, there was A$1.4 million of unused credit under Facility A, less than A$0.1 million of unused credit under Facility B and Facility C, and A$4.3 million of unused credit under Facility D.

Costs incurred in connection with securing the Facility Agreement, including fees paid to legal advisors and third parties, are deferred and amortized to interest expense over the term of the Facility Agreement. As of June 30, 2026, total unamortized debt issuance costs were A$0.5 million. During the year ended June 30, 2026 and 2025, the Group recorded A$0.3 million and A$0.2 million, respectively, as amortization of deferred debt issuance costs as a part of interest expense.

In December 2024, Tamboran B1 Operator signed a Development Agreement ("DA") with APA Group ("APA") that defines the conditions under which APA will design and construct the SPP. Under the DA, Tamboran B1 Operator is required to put in place bank guarantees that cover approximately two-thirds of APA's projected construction cost. As of June 30, 2026, Tamboran had drawn down A$27.4 million in bank guarantees related to the SPP. Pursuant to the Gas Transportation Agreement ("GTA") signed with APA, the bank guarantees will be released by APA once certain performance conditions are met and first gas has been delivered to the NT Government under the Gas Sales Agreement ("GSA"). APA may call on the bank guarantees if certain defaults under the DA or GTA remain unremedied, which in turn triggers a requirement by Tamboran B1 Operator to deposit cash amounts sufficient to cover the bank guarantees under the Facility Agreement with Macquarie.

Note 16 – Related Party Transactions

The Group had related party transactions with two shareholders identified as related parties, H&P and Mr. Bryan Sheffield ("Mr. Bryan Sheffield"). The transactions for the years ended June 30, 2026 and 2025 are as follows.

H&P

During the year ended June 30, 2023, the Group entered into a strategic alliance with H&P and secured a $15.0 million equity investment from H&P (and as a consequence, John Bell Sr., a member of the H&P Executive Leadership Team (the "H&P appointee") was appointed as a director of the Group). The strategic alliance resulted in H&P supporting the Group's development plans in the Beetaloo Basin through their equity investment in the Company while at the same time executing on H&P's strategy to gain more international exposure through the use of drilling rigs in Australia.

On July 1, 2023, the Group entered into a lease with H&P for the use of the FlexRig® for a period of 25 months period (Refer Note 6). During the year ended June 30, 2026, Mr. Bell resigned from his position as a director of the Group. Consequently, H&P is no longer a related party of the Group.

Mr. Bryan Sheffield

During the year ended June 30, 2026, the Group transacted with DWE and DWI, which are wholly owned by Formentera Australia Fund, LP, which is managed by Formentera Partners, LP, a private equity firm of which Mr. Bryan Sheffield serves as managing partner. Mr. Bryan Sheffield has been a shareholder in the Company since November 2021.

The Group and DWE jointly own a 50/50 joint venture referred to as TB1 and the Group and DWI jointly own a 50/50 joint venture referred to as SPCF Sub Trust (Refer Note 4).

During the years ended June 30, 2026 and 2025, DWE's share of expenditure for the Beetaloo Joint Venture for which contributions were due was $71.3 million and $55.1 million, respectively. As of June 30, 2026 and 2025, the Group had a joint interest billing receivable owing from DWE in the amount of $1.5 million and $7.1 million, respectively.

Subsequent to the announcement of the Falcon Acquisition, DWE and the Group entered into an arrangement to cover and pay (in agreed upon proportions for different areas of interest) for the cash calls due from Falcon Australia to TB2. As of June 30, 2026, the Group has a payable, in accounts payable and accrued expenses, owing to DWE of $1.8 million, which represents the portion of Falcon Australia cash calls DWE has paid to date.

During the year ended June 30, 2026 and 2025, DWI's share of expenditure for SPCF was nominal and $3.6 million, respectively. During the year ended June 30, 2026, SPCF Sub Trust reimbursed DWI for the contributions made for the SPCF. All SPCF expenditures, incurred during the year ended June 30, 2026, with the exception of expenditures for the SPCF expansion, were funded through long-term debt under the Syndicated Facility. As of June 30, 2026, there were no joint interest billings owing to DWI or receivable from DWI as the expenditure is expected to be funded by Syndicated Facility through the end of construction (Refer Note 8). As of June 30, 2025, the Group had advances against joint interest billings owing to DWI in the amount of $0.5 million.

During the year ended June 30, 2025, the Company issued 312,500 shares of common stock to DWE in satisfaction of the Group's obligation towards the Checkerboard fee.

During the year ended June 30, 2025, the SPCF assets were transferred from TB1 to the SPCF Sub Trust (Refer Note 4). Subsequent to the transfer, cash calls were issued to DWI.

Note 17 – Subsequent Events

EP 117, 98 and 76 Permit Applications

A variation application was submitted to DME in September 2025 to vary the minimum work program for years 3, 4 and 5. On July 3, 2026 the DME approved variations to the minimum work program commitments of EP 98 for years 3, 4 and 5 and EP 117 for years 3 and 4. The DME did not approve variations to years 4 and 5 for EP 76.

Beetaloo JOA Letter Agreement

On July 8, 2026, the Company and DWE entered into a letter agreement establishing interim funding and voting arrangements under the Beetaloo JOA, pending the grant of the retention licences and the interest realignment contemplated by the JVSA Addendum and the Checkerboard Strategy. During this interim period, the Group and DWE will each fund, and be deemed entitled to vote, an agreed percentage of the obligations and rights attributable to each area, without amending their respective equity interests in TB1 or the voting thresholds under the TB1 JVSA, and the arrangements terminate upon the grant of the last of the retention licenses (subject to earlier termination rights held by DWE over the BCDA and South FSDA areas).

Acquisition of Redeemable Noncontrolling Interest

On July 23, 2026, the Company completed the acquisition of FOGA minority stock held by sophisticated investors in exchange of 60,259 shares of Tamboran common stock.

EP 136 Permit Application

A renewal application for EP 136 was submitted to the Department of Mining and Energy ("DME") in November 2025, requesting an extension of the permit for a period of 18 months to January 2031. On July 28, 2026 the request for this extension was not granted but the DME did grant changes to the program which varied the work program conditions for years 2 through 5, suspended the work program conditions of year 2 for a period of twelve (12) months from July 23, 2026 to July 23, 2027 and extended the term of the EP for a period of twelve (12) months from July 23, 2029 to July 23, 2030. These changes were effective as of July 23, 2026.

Stamp Duty Payments

On July 23, 2026, the Company lodged the stamp duty assessment for the Falcon Acquisition with the NT Government and subsequently paid the stamp duty on July 28, 2026 (Refer to Note 7).

In September 2026, the stamp duty assessed for the Checkerboard Sale and Purchase Deeds (Refer to Note 7) was paid to the NT Government.

Commencement of Natural Gas Production & SPCF Commissioning

SPP achieved practical completion on July 17, 2026. On August 26, 2026, Tamboran commenced the commissioning of the SPCF with gas backflowed from the SPP. In early September 2026, Tamboran commenced initial gas sales from the Group's Shenandoah South 2 pad. The Group's exploration and evaluation projects remain pending the determination of economically recoverable proven and probable reserves for the fiscal year ended June 30, 2026 and through the date this report is available for issuance.

The Group has evaluated its subsequent events occurring after June 30, 2026, through September 25, 2026, 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 18 – 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 fiscal years 2026 and 2025 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, 2026 and 2025 were as follows (in thousands):

	For the years ended June 30,	
	2026	**2025**
Property acquisition costs:		
Proved	$ —	$ —
Unproved [(1)]	287,049	—
Exploration costs:		
Geological and geophysical	3,336	4,112
Development costs	209,090	132,468
Total cost incurred	499,475	136,580
Asset retirement obligations	10,807	524
Total cost incurred	$ 510,282	$ 137,104

(1) Includes acquisition cost of $1.6 million related to the Mako Trough property in Hungary pursuant to the Falcon Acquisition. The Group did not undertake any oil and natural gas activities in the Mako Trough property.

Capitalized Costs

Capitalized costs consist of the 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, 2026 and 2025 (in thousands):

	June 30,	
	2026	**2025**
Natural gas properties, successful efforts method:		
Unproved properties	$ 807,036	$ 342,314
Accumulated impairment to unproved properties	—	—
Net unproved properties	$ 807,036	$ 342,314
Assets under construction- natural gas equipment	72,287	24,441
	$ 879,323	$ 366,755

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 costs and 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, 2026 and 2025.