ATHABASCA
OIL CORPORATION

Annual Information Form

FOR THE YEAR ENDED DECEMBER 31, 2024

March 5, 2025

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DEFINITIONS

Unless otherwise defined herein, all Capitalized terms in this Annual Information Form have the meanings set forth in the Glossary of Defined Terms.

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements and information. The use of words such as "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "projection", "forecast", "scheduled", "intend", "should", "believe", "predict", "pursue" and "potential" and similar expressions are intended to identify forward-looking statements. Since forward-looking statements address future events or conditions, they involve inherent risks and uncertainties. Actual results or events could differ materially from those anticipated in such statements. No assurance can be given that expectations will prove to be correct and forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as at the date of this Annual Information Form.

This Annual Information Form contains forward-looking statements that include, but are not limited to:

- the reserve and resource potential of Athabasca's assets, including developments plans thereof;
- our business strategy, objectives, opportunities and expectations;
- access to third-party infrastructure, including pipeline and rail;
- our capital expenditure program, future capital requirements and future sources of funding;
- our projections of commodity prices, costs and netbacks;
- anticipated future abandonment and reclamation costs;
- anticipated timing for the payment of Canadian income taxes;
- supply and demand fundamentals for energy, including oil, bitumen blend, natural gas and diluent;
- timing and size of Athabasca's operations, development projects, expected timelines, optimizations and anticipated production levels;
- Athabasca's growth outlook and how that growth outlook is funded;
- production and design capacity of Athabasca's assets;
- the estimated quantity and value of our reserves and contingent resources;
- our anticipated land expiries;
- drilling and completion plans (including the expected timing for wells to be brought on stream at Leismer, Hangingstone and Duvernay Energy);
- the timing and nature of return of capital operations;
- industry conditions, including the timing, nature and expected impact of certain infrastructure projects and regulations;
- the regulatory framework governing royalties, taxes and environmental matters;
- environmental performance, sustainability and our ESG goals; and
- the anticipated impact of the factors discussed under the headings "*Industry Conditions*" and "*Risk Factors*".

The forward-looking statements are based on key expectations and assumptions that include, but are not limited to:

- general economic and financial market conditions;
- commodity prices, exchange rates, interest rates and inflation rates;
- future sources of funding for Athabasca's capital programs and Athabasca's ability to obtain financing on acceptable terms;
- the regulatory framework governing royalties, taxes, environmental protection and foreign investment;
- Athabasca's ability to transport and market production;
- our future production levels;
- the success of our exploration and development activities;
- operating costs and capital expenditures;
- recoverability of Athabasca's reserves and Contingent Resources;
- Athabasca's future debt levels;

- compliance of counterparties in contractual arrangements with Athabasca;
- geological and engineering estimates in respect of Athabasca's reserves and Contingent Resources;
- estimated abandonment and reclamation costs;
- the prevailing climatic conditions in Athabasca's operating locations;
- collection risk of outstanding accounts receivable from third parties;
- our ability to access and implement all technology and equipment necessary to achieve expected future results, including in respect of climate and GHG emission intensity reduction targets and ambitions and the commercial viability and scalability of emission intensity reduction strategies and related technology and products; and
- the impact of competition on Athabasca.

Some of the risks that could affect our future results and cause results to differ materially from those expressed in the forward-looking statements include, but are not limited to:

- Weakness in the Oil and Gas Industry;
- Exploration, Development and Production Risks;
- Prices, Markets and Marketing;
- Market Conditions;
- Trade Relations and Tariffs;
- Climate Change and Carbon Pricing Risk;
- Statutes and Regulations Regarding the Environment;
- Regulatory Environment and Changes in Applicable Law;
- Gathering and Processing Facilities, Pipeline Systems and Rail;
- Reputation and Public Perception of the Oil and Gas Sector;
- Environment, Social and Governance Goals;
- Political Uncertainty;
- State of the Capital Markets;
- Ability to Finance Capital Requirements;
- Access To Capital and Insurance;
- Abandonment and Reclamation Costs;
- Changing Demand for Oil and Natural Gas Products;
- Anticipated Benefits of Acquisitions and Dispositions;
- Royalty Regimes;
- Foreign Exchange Rates and Interest Rates;
- Reserves;
- Hedging;
- Operational Dependence;
- Operating Costs;
- Project Risks;
- Supply Chain Disruption;
- Financial Assurances;
- Diluent Supply;
- Third-Party Credit Risk;
- Indigenous Claims;
- Reliance on Key Personnel and Operators;
- Income Tax;
- Cybersecurity;
- Advanced Technologies;
- Hydraulic Fracturing;
- Liability Management;
- Seasonality and Weather Conditions;
- Unexpected Events;
- Internal Controls;

- Limitations of Insurance;
- Litigation;
- Natural Gas Overlying Bitumen Resources;
- Competition;
- Chain of Title and Expiration of Licenses and Leases;
- Breaches of Confidentiality;
- New Industry Related Activities or New Geographical Areas;
- Water Use Restrictions and/or Limited Access to Water;
- Relationship with Duvernay Energy Corporation;
- Management Estimates and Assumptions;
- Third-Party Claims;
- Conflicts of Interest;
- Inflation and Cost Management;
- Credit Ratings;
- Growth Management;
- Impact of Pandemics;
- Ability of Investors Resident in the United States to Enforce Civil Remedies in Canada; and
- Risks related to our Debt and Securities,

in each case as further described under the heading "*Risk Factors*".

Readers are cautioned that our list of risk factors should not be construed as exhaustive. In addition, statements relating to "reserves" and "resources" are deemed to be forward-looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future.

Although management of the Company believes that the assumptions underlying and the expectations reflected in the forward-looking information are reasonable, significant risks and uncertainties are involved in such information. Management can give no assurances that its assumptions, estimates and expectations will prove to have been correct. Forward-looking information should not be read as guarantees of future performance or results and will not necessarily be accurate indications of whether such performance or results will be achieved. Many factors that are beyond Athabasca's control could cause actual results to differ materially from the results discussed in the forward-looking statements.

The forward-looking statements included in this Annual Information Form are expressly qualified by this cautionary statement and are made as at the date of this Annual Information Form. The Company does not undertake any obligation to publicly update or revise any forward-looking statements, except as required by applicable securities laws.

ABBREVIATIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

bbl	barrel
bbl/d	barrels per day
BOE or boe	barrels of oil equivalent
Boe/d	barrels of oil equivalent per day
MMboe	million barrels of oil equivalent
Mbbl	thousand barrels
MMbbl	million barrels
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Bcf	billion cubic feet

OIL AND GAS INFORMATION AND OTHER ADVISORIES

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

The management estimate of 444 Duvernay Energy drilling locations referenced include: 87 proved undeveloped or non-producing locations and 85 probable undeveloped locations for a total of 172 booked locations with the balance being unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the Company's most recent independent reserves evaluation as prepared by McDaniel as at December 31, 2024 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal management estimates. Unbooked locations do not have attributed reserves or resources (including contingent or prospective). Unbooked locations have been identified by management as an estimation of Athabasca's multi-year drilling activities expected to occur beyond the existing reserve bookings and are based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof, is ultimately dependent upon the availability of funding, oil and natural gas prices, provincial fiscal and royalty policies, costs, actual drilling results, additional reservoir information that is obtained and other factors.

Netback per boe is a non-GAAP ratio. Netback is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring operating performance. Athabasca's netback calculation as disclosed herein is aligned with the definition found in the COGE Handbook. Netback is defined as gross sales less royalties, transportation and marketing and operating expenses, and adding or subtracting realized gains (losses) on commodity risk management contracts. Netback per boe is divided by sales volumes. The sales price and sales volumes exclude the impact of purchased condensate. Condensate is blended with crude oil to transport it to market. This measure should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

CONVERSIONS AND CONVENTIONS

The following table sets forth certain standard conversions from Standard Imperial units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.315
Bbl	cubic metres	0.159
cubic metres	Bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.500

CURRENCY

Unless otherwise indicated, all dollar amounts are expressed in Canadian dollars and all references to "$" or "C$" are to Canadian dollars and all references to "US$" are to United States dollars.

OUR COMPANY

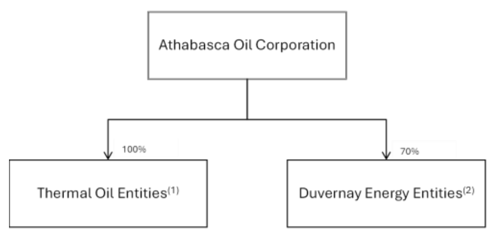
Name, Address and Incorporation

The Company was incorporated as "Athabasca Oil Sands Corp." under the ABCA on August 23, 2006 and we filed articles of amendment to remove our private company restrictions on September 1, 2006. On March 22, 2010, we filed articles of amendment to create first preferred shares, issuable in series, and second preferred shares, issuable in series. On May 10, 2012, we filed articles of amendment to change our name from "Athabasca Oil Sands Corp." to "Athabasca Oil Corporation".

Our head office is located at Suite 1200, 215 – 9th Avenue S.W., Calgary, Alberta T2P 1K3, and our registered office is located at Suite 3700, 400 – 3rd Avenue S.W., Calgary, Alberta T2P 4H2.

Intercorporate Relationships

The following simplified organizational chart and related notes illustrate our intercorporate relationships and our material subsidiaries, as at December 31, 2024, including the percentage of votes attaching to the voting securities of the entities that are beneficially owned, controlled or directed (directly or indirectly) by us. Each of our subsidiaries is incorporated or formed under the laws of the Province of Alberta. See "*Development of our Business – Recent Developments*".



Notes:

(1) The "Thermal Oil Entities" are Alberta corporations and Alberta-formed partnerships that hold the Company's Thermal Oil assets and that are directly or indirectly wholly-owned by the Company: AOC Dover West Corp., AOC Grosmont Ltd., AOC Carbonates Ltd., AOC (ELE) Corp., AOC Birch Corp., AOC Dover West Partnership, AOC Grosmont Partnership, AOC Carbonates Partnership, AOC Hangingstone Partnership, AOC Birch Partnership, AOC Leismer Corner Partnership and 1686303 Alberta Ltd.

(2) Duvernay Energy Entities are Alberta corporations and Alberta formed partnerships that hold the Company's Duvernay Energy assets and that are directly or indirectly partially owned by the Company: Duvernay Energy Corporation, AOC Kaybob Corporation and AOC Kaybob Partnership. Athabasca has a 70% equity interest in the Duvernay Energy Entities each of which operate as a subsidiary under Athabasca's control.

Our Common Shares trade on the TSX under the trading symbol "ATH".

DEVELOPMENT OF OUR BUSINESS

Developments in 2024

On August 9, 2024, Athabasca closed a private placement (the "**Offering**") of $200 million aggregate principal amount of 6.75% senior unsecured notes due August 9, 2029 (the "**2029 Notes**"). The net proceeds from the Offering together with cash on hand were used to fully repay Athabasca's existing US$157 million aggregate principal amount of 9.75% senior secured second lien notes due November 1, 2026 (the " **2026 Notes**"). See "*Capital Structure – 2029 Notes*" for additional information.

On March 18, 2024, Athabasca renewed its Normal Course Issuer Bid, pursuant to which the Company is authorized to purchase for cancellation up to 55,423,786 common shares between March 18, 2024 and March 17, 2025. During 2024, the Company acquired and cancelled approximately 61.3 million shares returning $317.6 million to shareholders under its Normal Course Issuer Bid.

During the fourth quarter of 2023, Athabasca entered into transaction agreements with Cenovus to create Duvernay Energy Corporation ("**Duvernay Energy**", and the "**Transaction**"). On February 6, 2024, the Transaction closed. Athabasca and Cenovus Edson Partnership (an affiliate of Cenovus Energy Inc.) ("**Cenovus**") have contributed assets into Duvernay Energy, combining Athabasca's existing Duvernay assets, Athabasca's new 100% working interest Duvernay assets and Cenovus' 100% working interest Duvernay assets. Athabasca owns a 70% equity interest in Duvernay Energy with Cenovus owning the remaining 30% equity interest. Duvernay Energy is a privately held subsidiary of Athabasca and is managed by Athabasca through a management and operating services agreement. Following closing of the Transaction, the Company renamed its Light Oil Division "Duvernay Energy".

At Kaybob, production of Duvernay Energy averaged 3,310 boe/d (76% liquids) in 2024.The Company drilled eight (5.9 net) wells and brought on stream five (2.9 net) wells during 2024 in addition to initiating infrastructure projects to facilitate development on its newly operated lands.

At Leismer, bitumen production averaged 26,103 bbl/d in 2024. In Q1 Athabasca completed the facility expansion at Leismer increasing the plant capacity to 28,000 bbl/d. In Q2 Athabasca brought on-stream three redrills on Pad 4, four infills on Pad 7, and four new well pairs on Pad 8S resulting in production ramping up to a record production rate of ~28,000 bbl/d in June. Additionally, in the second half of 2024, Athabasca drilled four well pairs on Pad 10S and six redrills on Pad 1 which are expected to be brought on-stream by Q2 2025.

Following the brownfield expansion project, in Q3 Athabasca sanctioned a facility expansion that is expected to progressively grow the facility to 40,000 bbl/d, with full capacity expected to be achieved in late 2027.

At Hangingstone, bitumen production averaged 7,402 bbl/d in 2024. The Company drilled two new extended lateral length well pairs (1,400 meters laterals per well) to sustain current production rates. Both wells started steaming in Q4 2024 and are expected to be brought on-stream in Q1 2025. Athabasca continued non-condensable gas co-injection that reduced the steam to oil ratio to 3.4 in 2024.

Developments in 2023

During the fourth quarter of 2023, Athabasca entered into the Transaction with Cenovus to create Duvernay Energy.

In 2023, Athabasca commenced a Normal Course Issuer Bid, which expired on March 15, 2024. During 2023, the Company acquired, and cancelled, approximately 44.2 million shares at an average price of $3.58 per share, returning $158.6 million to shareholders.

In July 2023, Athabasca sold non-core light oil assets for $160 million. Athabasca sold its 70% operated working interest in Placid targeting the Montney, its 30% non-operated working interest in Saxon and Simonette targeting the Duvernay and other associated non-core Placid Montney assets to a private company for $160 million in cash, prior to adjustments. Up to closing of the transaction, production at Placid averaged 1,904 boe/d (41% liquids) in 2023**.**

In May 2023, due to the Alberta wildfires, Athabasca shut-in two of its facilities at Kaybob within its Light Oil operations. No damage was sustained, and production was restored in June 2023.

At Kaybob, production averaged 2,340 boe/d (71% liquids) in 2023. The Company spud a two-well 100% working interest pad at Kaybob East that was placed on production in the first half of 2024. Following the closing of the Transaction the Company has exposure to approximately 200,000 gross acres across Kaybob West, Kaybob North, Kaybob East and Two Creeks with management estimates of ~444 future well locations, established infrastructure, and minimal near-term land retention requirements.

At Leismer, bitumen production averaged 22,497 bbl/d in 2023 following the ramp-up of the five sustaining well pairs on Pad 8M. In August 2023 the Leismer facility ramped up to a production rate of approximately 24,500 bbl/d. In 2023 the Company completed drilling four well pairs on Pad 8S and four infill wells on Pad 7. These new wells started steaming in December 2023.

At Hangingstone, bitumen production averaged 7,749 bbl/d in 2023. Non-condensable gas co-injection has aided in pressure support and reduced energy usage. Hangingstone's steam to oil ratio averaged 3.6 in 2023. Activity at Hangingstone was focused on initial work for the Pad AA extension in anticipation of drilling sustaining well pairs in 2024 to maintain base production.

In 2023, Athabasca redeemed US$18.2 million of its 2026 Notes, achieving the Company's debt reduction target of

US$175 million or 50% of the original US$350 million of 2026 Notes issued in October 2021.

Developments in 2022

At Leismer, bitumen production averaged 20,135 bbl/d in 2022. In May 2022, the Company completed a ten-day planned facility turnaround with a peak workforce of roughly 550 people completing approximately 92,000 hours of work with no lost time incidents or reportable spills. The Company ramped up production of the first five well pairs at Pad 8 and completed drilling and completion activities on five additional well pairs in October 2022.

At Hangingstone, bitumen production averaged 8,854 bbl/d in 2022. Reservoir performance continues to be supported by strong facility runtime and non-condensable gas co-injection is aiding in reduced energy usage.

At Placid, production averaged 3,232 boe/d (42% liquids) in 2022. At Kaybob, production averaged 3,041 boe/d (72% liquids) in 2022. Light Oil capital expenditures were primarily incurred at Greater Kaybob for the completion and infrastructure work for three gross wells previously drilled in 2019.

In 2022, Athabasca redeemed US$174.8 million of its 2026 Notes, effectively achieving the Company's debt reduction target of US$175 million or 50% of the original US$350 million 2026 Notes issued in October 2021.

Significant Acquisitions

We have not completed any significant acquisitions during our most recently completed financial year for which disclosure is required under NI 51-102.

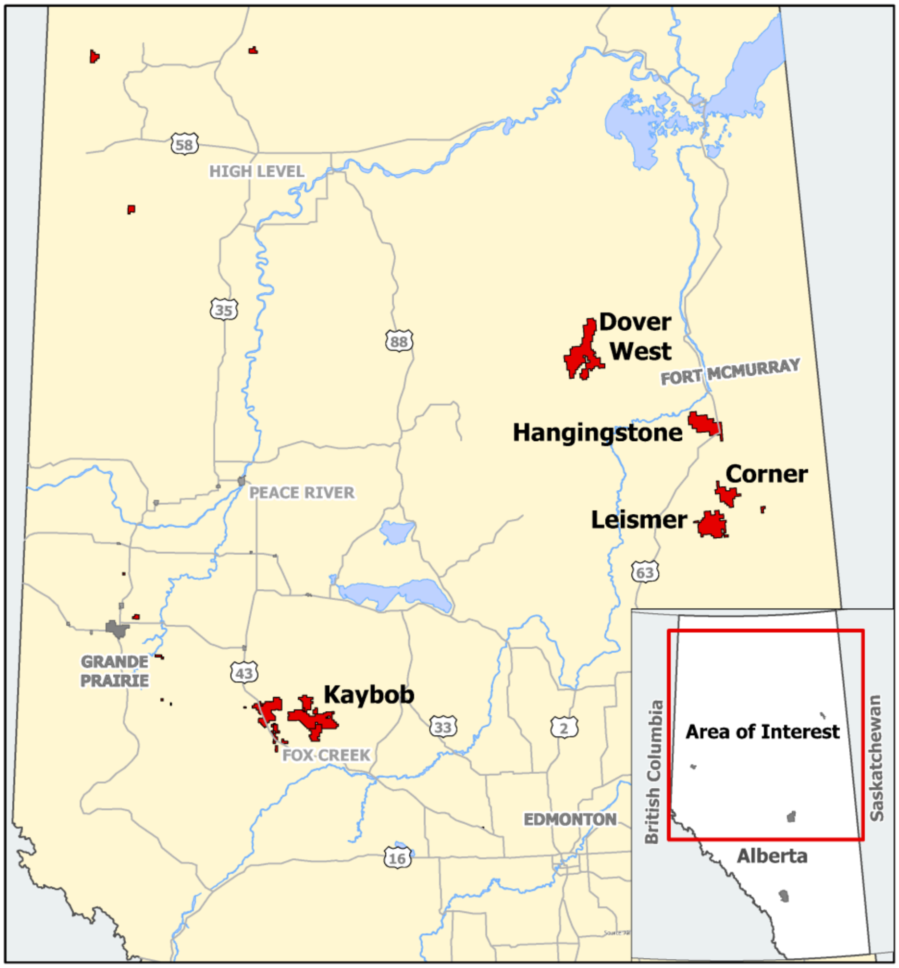
DESCRIPTION OF OUR BUSINESS

Our Development Strategy for Our Principal Properties

Athabasca is a liquids-weighted intermediate producer with exposure to Canada's premier resource plays (oil sands, Duvernay) through its Thermal Oil assets and Duvernay Energy. Athabasca's Thermal Oil assets consist of its cornerstone producing Leismer asset, its producing Hangingstone asset, the high-quality Corner lease which is an extension of the Leismer field and the Dover West exploration asset in the Athabasca region of northeastern Alberta. Duvernay Energy, a privately held subsidiary of Athabasca, commenced operations on February 6, 2024 following the Transaction. Duvernay Energy produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Duvernay shale play in the Greater Kaybob area near the town of Fox Creek, Alberta.

Athabasca's strategy is focused on maximizing cash flow per share growth through investing in high margin projects and executing on return of capital initiatives. The Company has long term growth optionality across a deep inventory of high-quality Thermal Oil projects and flexible Duvernay development opportunities. This balanced portfolio provides shareholders with differentiated exposure to liquids weighted production and significant long reserve life assets.

The following map illustrates the locations of our principal assets as at December 31, 2024:



Athabasca (Thermal Oil)

Athabasca (Thermal Oil) consists of two operating oil sands SAGD projects and an exploration area in the Athabasca region of northeastern Alberta. Athabasca (Thermal Oil) provides Athabasca with a material low decline production base that generates significant free cash flow in the current commodity price environment.

As at December 31, 2024, Athabasca (Thermal Oil) held approximately 350,000 net acres of oil sands rights in the Athabasca region of northeastern Alberta. Sales from Athabasca (Thermal Oil), for the year ended December 31, 2024, averaged 33,505 bbl/d of bitumen.

Athabasca (Thermal Oil) has transportation and storage agreements at the Cheecham Terminal and on the Enbridge Waupisoo transportation pipeline which then accesses multiple sales points from Edmonton, Alberta.

All references to bbl in the Athabasca (Thermal Oil) section refer to bitumen.

Leismer and Corner Assets

The Leismer and Corner assets are located in northeastern Alberta and are 100% working interest projects. Leismer includes approximately 81,000 net acres of oil sands leases and Corner includes approximately 44,000 net acres of oil sands leases. The Leismer Project is a SAGD project that was commissioned in 2010. The facility has a current capacity of 28,000 bbl/d with regulatory approval to expand to 40,000 bbl/d capacity.

The Leismer Project averaged 26,103 bbl/d production in 2024. In July 2024, the Company sanctioned a facility expansion to progressively grow the facility to 40,000 bbl/d, with full capacity expected to be achieved in late 2027.

McDaniel has assigned approximately 332 MMbbl of proved reserves and 694 MMbbl of proved plus probable reserves on a gross reserves basis to the Leismer assets as at December 31, 2024. See "*Statement of Reserves Data*".

Leismer's significant resource base provides optionality for further expansion phases which could increase the total capacity to approximately 80,000 bbl/d. Development of the Leismer assets to this capacity is contingent upon various factors. For further details relating to Leismer expansions, please see "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*" and "Risk Factors – Reserves".

For Corner, McDaniel has assigned approximately 351 MMbbl of proved plus probable reserves on a gross reserves basis as at December 31, 2024. See "*Statement of Reserves Data*".

Future SAGD development for the Corner asset includes the first phase that has a regulatory approval for 40,000 bbl/d (Corner Project 1) followed by a future phase that would increase the total facility capacity to 90,000 bbl/d (Corner Project 2). Development of the Corner assets is contingent upon various factors. For further detail relating to potential future development plans for the Corner assets please see "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*".

Hangingstone Assets

The Hangingstone assets are located approximately 20 kilometres southwest of the city of Fort McMurray in northeastern Alberta and include a concentrated, contiguous land base of approximately 76,000 net acres. Athabasca owns a 100% working interest. The Hangingstone Project achieved first production in 2015. The Hangingstone Project is a SAGD project that was commissioned in 2015 and has a facility capacity of 12,000 bbl/d. The Hangingstone Project averaged 7,402 bbl/d of production in 2024.

McDaniel has assigned approximately 72 MMbbl of proved reserves and 163 MMbbl of proved plus probable reserves on a gross reserves basis to the Hangingstone assets as at December 31, 2024. See "*Statement of Reserves Data*".

Duvernay Energy

Duvernay Energy, a privately held subsidiary of Athabasca, commenced operations on February 6, 2024 following the Transaction, which involved the transfer of certain assets, pursuant to an agreement involving Athabasca and Cenovus. Athabasca received a 70% equity interest in exchange for cash, petroleum and natural gas assets and the transferred interest of its wholly owned Kaybob partnership. Cenovus received a 30% equity interest in exchange for cash and petroleum and natural gas assets. Duvernay Energy is managed by Athabasca through a management and operating services agreement. With the completion of the Transaction, Athabasca's former Light Oil operating segment has been renamed Duvernay Energy and with Duvernay Energy operating as a subsidiary under Athabasca's control it is consolidated within Athabasca's consolidated financial statements.

In accordance with NI 51-101, the Independent Report and the reserves data for Athabasca's consolidated reserves set forth below, includes (unless otherwise indicated) 100% of the reserves and future net revenue attributable to Duvernay Energy's properties, without reduction to reflect the 30% minority interest of Cenovus in Duvernay Energy. Duvernay Energy's reserve data reflects its 30% net working interest in the Kaybob JDA with Murphy. See "S*tatement of Reserves Data – Duvernay Energy*" and "Statement of Reserves Data – Independent Report".

Duvernay Energy produces light oil and liquids-rich natural gas from unconventional reservoirs. Development has been focused on the Duvernay shale play in the Greater Kaybob area near the town of Fox Creek, Alberta. As at December 31, 2024, the Greater Kaybob assets had approximately 73 MMboe of proved plus probable reserves. The Duvernay Energy assets are supported by operated regional infrastructure consisting of two batteries and a network of gas pipelines which connect the facilities to two regional third party gas processing plants.

In Greater Kaybob, Duvernay Energy has approximately 200,000 gross acres of commercially prospective Duvernay lands with exposure to both liquids-rich gas and volatile oil opportunities. This land is comprised of a 100% operated interest in approximately 46,000 gross acres and a 30% non-operated interest in approximately 157,000 gross acres with an inventory of approximately 444 gross (204 net) drilling locations.

Thermal Oil Exploration

Dover West Assets

Athabasca has a 100% working interest in its Dover West assets which are located 90 kilometres north of Fort McMurray. There are no immediate development plans or current capital allocated for these assets. The Dover West assets are geologically unique in that they contain three primary bitumen reservoirs.

As at December 31, 2024, the Dover West assets were comprised of a large contiguous land base of approximately 149,000 net acres. The bitumen resource associated to the McMurray formation and the Wabiskaw Member of the Clearwater Formation (the Dover West Sands) were booked as contingent resource as the development of these assets is contingent upon various factors. For further details about the Dover West assets, please see "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*" and "Risk Factors – Reserves".

Athabasca sees further resource potential in the Leduc and Cooking Lake formations of the Devonian Woodbend Group (the Dover West Carbonates) but, at this time, no resources have been booked.

Competition

Our industry is competitive in all its phases. We compete with numerous other participants in the acquisition, exploration and development of our assets and in the marketing of oil and natural gas. Our competitors include resource companies that may have greater financial resources, staff and facilities than us. We believe that our competitive position is, on the whole, equivalent to that of other producers of similar size and at a similar stage of development.

Environmental, Social and Governance Policies

We have a longstanding commitment to Environmental, Social, and Governance ("**ESG**") initiatives and are proud of the work we do to take care of the environment and the communities where we operate. We are committed to environmental protection and health and safety by integrating these essential principles and practices through our management systems and occupational health and safety programs. We strive to conduct our activities in a way that safeguards our employees, contractors, the environment and the public. Preserving air quality, biodiversity and water quality are considerations we address in all phases of our projects, including planning, construction, operations and reclamation. We work with regulators, industry peers, multi-stakeholder organizations and communities to share information and continuously improve our environmental performance.

We believe that measurement is key to evaluating our work, setting goals, and making year over year progress. Our ESG strategy and performance is reviewed, considered, and fully integrated at the Board level. Our management team and Board are committed to incorporating ESG considerations and the application of technology in all our capital allocation decisions.

Athabasca's social goals included a Total Recordable Injury Frequency target of less than 0.5 in 2024 (with an aspiration to harm no people and no reportable hydrocarbon spills), to maintain our current level of financial support in the communities where we live and work, and a formal roll-out of our corporate values through employee values workshops.

Athabasca's governance goals included >30% female board representation from our 2024 annual meeting of Shareholders of the Company onwards. Additionally, the Company provides ongoing education and training for cyber security awareness for all employees.

Athabasca supports the communities in which we live and operate and strives to build long-term relationships with stakeholders in such communities. Our community engagement is guided by Athabasca's Three Pillars of Giving Back to the Community: our people, Indigenous relations, and community. The Company engages with Indigenous stakeholders at all stages of a project's development and early in our procurement processes to ensure local services from vendors from Indigenous communities are considered. Athabasca provides funding to a variety of organizations, charities and outreach programs that benefit local communities and Albertans throughout the province. Athabasca also supports a number of educational initiatives including scholarships, endowments and practicum opportunities at universities and colleges across Alberta.

Seasonal Factors

The exploration for and development of reserves is dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up as well as forest fires affect access in certain circumstances. Unexpected adverse weather conditions can have negative impacts on operations and costs.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected during the remainder of 2025 by the renegotiation or termination of contracts.

Personnel

As at December 31, 2024, Athabasca had 181 employees (comprised of 80 head office and 101 field employees).

STATEMENT OF RESERVES DATA

Independent Report

Athabasca is required to report its reserves and to provide other oil and gas information in accordance with NI 51-101. Athabasca engaged McDaniel to independently assess and evaluate Athabasca's bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves as at December 31, 2024. McDaniel carried out its evaluation in accordance with standards established in NI 51-101. Those standards require that the bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves be prepared in accordance with the COGE Handbook. The reserves estimates set out below reflect the Company's working interests (as at December 31, 2024) in the Leismer, Hangingstone and Corner assets and in Duvernay Energy.

In accordance with NI 51-101, the Independent Report and the reserves data for Athabasca's consolidated reserves set forth below, includes (unless otherwise indicated) 100% of the reserves and future net revenue attributable to Duvernay Energy's properties, without reduction to reflect the 30% minority interest of Cenovus in Duvernay Energy. Duvernay Energy's reserve data reflects its 30% net working interest in the Kaybob JDA with Murphy. See "S*tatement of Reserves Data – Duvernay Energy*" and "*Description of Our Business – Our Development Strategy for Our Principal Properties – Duvernay Energy"*.

The effective date of the information provided below is December 31, 2024 and the preparation date of the Independent Report is March 5, 2025. McDaniel's responsibility is to express opinions on the bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves including the associated estimated net present values. The preparation and disclosure of the reported reserves estimates is the responsibility of Athabasca's management.

McDaniel's Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor is set forth in Appendix C to this Annual Information Form. Athabasca's Report of Management and Directors on Oil and Gas Disclosure in the form of NI 51-101F3 is set forth in Appendix B to this Annual Information Form. The reserves estimates presented in the Independent Report are based upon the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

Information relating to Athabasca's reserves constitutes forward-looking information, which is subject to certain risks and uncertainties. See "*Forward-Looking Statements*" for additional information.

Reserves Classifications

Reserves Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as at a given date, based on analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions. Reserves are classified as proved reserves or probable reserves according to the degree of certainty associated with the estimates. These categories may be further divided into developed and undeveloped categories.

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. Developed reserves may be further classified as developing producing reserves, meaning those reserves that are expected to be recovered from wells on production at the time of the estimate, and developing non-producing reserves, meaning those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown. Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Consolidated Reserves Estimates

Set out below is a summary of Athabasca's reserves, as well as the estimated value of future net revenue of Athabasca from the reserves, as at December 31, 2024, evaluated in the Independent Report. The pricing used in the forecast price evaluations for all assets is set forth below under "*Price Forecast*".

As at December 31, 2024, Athabasca's bitumen reserves were contained in its Leismer, Hangingstone and Corner assets. Proved reserves were assigned by McDaniel to the Leismer Project and the Hangingstone Project. Probable reserves were assigned by McDaniel to the Leismer Project 2, the Hangingstone Project, and the Corner Project 1. Athabasca's light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves are all associated with Duvernay Energy. Both proved reserves and probable reserves have been assigned by McDaniel to Duvernay Energy.

All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not represent the fair market value of Athabasca's reserves. There is no assurance that the forecast price assumptions that have been utilized by McDaniel will be realized and variances could be material. Other assumptions have been made by McDaniel and qualifications relating to costs and other matters are included in the Independent Report. The recovery and reserves estimates of Athabasca's properties described herein are estimates only. The actual reserves of Athabasca's properties may be greater or less than those calculated.

Summary of Consolidated Reserves Data – Forecast Prices and Costs as of December 31, 2024(1)(2)(7)(8)

Reserve Category	Bitumen		Tight Oil & Light/Medium Crude Oil		Conventional Natural Gas	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)
PROVED RESERVES						
Developed Producing	74,069	60,372	3,341	2,557	53	49
Developed Non-Producing	0	0	0	0	0	0
Undeveloped	330,361	217,392	22,937	19,109	0	0
TOTAL PROVED RESERVES	404,429	277,764	26,278	21,666	53	49
TOTAL PROBABLE RESERVES	804,561	505,615	21,537	16,317	11	10
TOTAL PROVED PLUS PROBABLE RESERVES	1,208,990	783,379	47,815	37,984	64	58
Shareholders of Parent	1,208,990	783,379	33,471	26,589	45	41
Non-Controlling Interests	0	0	14,345	11,395	19	18

Reserve Category	Shale Gas		Natural Gas Liquids		Oil Equivalent	
	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED RESERVES						
Developed Producing	9,350	8,711	649	517	79,626	64,906
Developed Non-Producing	0	0	0	0	0	0
Undeveloped	52,501	48,305	3,623	2,976	365,670	247,528
TOTAL PROVED RESERVES	61,850	57,016	4,271	3,492	445,296	312,434
TOTAL PROBABLE RESERVES	44,674	39,766	2,896	2,186	836,441	530,748
TOTAL PROVED PLUS PROBABLE RESERVES	106,525	96,782	7,167	5,679	1,281,737	843,182
Shareholders of Parent	74,567	67,748	5,017	3,975	1,259,913	825,241
Non-Controlling Interests	31,957	29,035	2,150	1,704	21,824	17,941

For notes, please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table.

Summary of Consolidated Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2024 (1)(2)(3)(4)(8)

Reserve Category	Before Income Tax Discounted at (%/year)					After Income Tax Discounted at (%/year)					Net Unit Value Before Income Tax at 10% Discount/Year	
	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	$/boe	$/Mcfe
PROVED RESERVES												
Developed Producing	$2,302	$2,072	$1,830	$1,629	$1,467	$2,250	$2,039	$1,807	$1,612	$1,455	$28.19	$4.70
Developed Non- Producing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0.00	$0.00
Undeveloped	$8,120	$3,671	$1,936	$1,140	$722	$6,239	$2,784	$1,441	$828	$508	$7.82	$1.30
TOTAL PROVED RESERVES	$10,422	$5,743	$3,766	$2,769	$2,189	$8,488	$4,822	$3,247	$2,440	$1,963	$12.05	$2.01
TOTAL PROBABLE RESERVES	$21,782	$6,639	$2,672	$1,219	$557	$16,726	$4,984	$1,929	$817	$313	$5.04	$0.84
TOTAL PROVED PLUS PROBABLE RESERVES	$32,204	$12,382	$6,438	$3,988	$2,746	$25,215	$9,806	$5,177	$3,257	$2,276	$7.64	$1.27
Shareholders of Parent	$31,688	$12,085	$6,254	$3,868	$2,666	$24,813	$9,580	$5,042	$3,174	$2,225	$10.27	$1.71
Non-Controlling Interests	$516	$297	$184	$120	$80	$402	$226	$135	$83	$51	$10.27	$1.71

For notes, please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table.

Consolidated Future Net Revenue (Undiscounted) – Forecast Prices and Cost as of December 31, 2024(1)(2)(3)(4)(8)

Reserve Category	Revenue ($MM)	Royalties ($MM)	Operating Costs ($MM)	Development Costs ($MM)	Abandonment and Reclamation Costs ($MM)	Future Net Revenue Before Future Income Tax Expense ($MM)	Future Income Tax Expense ($MM)	Future Net Revenue After Future Income Tax Expense ($MM)
PROVED RESERVES	$37,658	$11,900	$10,229	$4,538	$569	$10,422	$1,934	$8,488
PROBABLE RESERVES	$88,689	$33,398	$21,003	$11,948	$558	$21,782	$5,055	$16,726
PROVED PLUS PROBABLE	$126,348	$45,299	$31,232	$16,486	$1,127	$32,204	$6,989	$25,215

For notes, please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table.

Consolidated Future Net Revenue by Product Type – Forecast Prices and Costs as of December 31, 2024(1)(2)(3)(5)(6)(7)(8)

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Yr and net vol.)		
		$MM	$/bbl	$/Mcfe
PROVED RESERVES	Bitumen	$3,421	$12.32	$2.05
	Tight Oil/Light and Medium Oil	$345	$15.90	$2.65
	Conventional Natural Gas	$0	$0.00	$0.00
	Shale Gas	$0.16	$9.46	$1.58
	Total	**$3,766**	**$12.05**	**$2.01**
PROVED PLUS PROBABLE RESERVES	Bitumen	$5,824	$7.43	$1.24
	Tight Oil/Light and Medium Oil	$614	$16.16	$2.69
	Conventional Natural Gas	$0	$0.00	$0.00
	Shale Gas	$0.18	$9.82	$1.64
	Total	**$6,438**	**$7.64**	**$1.27**

For notes, please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table.

Consolidated Reconciliation of Reserves by Principal Product Type – Forecast Prices and Costs as of December 31, 2024(1)(2)(3)(5)(7)(8)

The following table sets forth a reconciliation of the changes of Athabasca's reserves estimates, before royalties, of bitumen, tight oil, light/medium crude oil, conventional natural gas, shale gas and NGL as of December 31, 2024, compared to such reserves as of December 31, 2023, based on the forecast price and cost assumptions that are described in Note (1) below.

Factors	Bitumen Gross Proved Reserves (MMbbl)	Bitumen Gross Probable Reserves (MMbbl)	Bitumen Gross Proved + Probable Reserves (MMbbl)	Tight Oil & Light/Medium Crude Oil Gross Proved Reserves (MMbbl)	Tight Oil & Light/Medium Crude Oil Gross Probable Reserves (MMbbl)	Tight Oil & Light/Medium Crude Oil Gross Proved + Probable Reserves (MMbbl)
December 31, 2023	404.0	811.7	1215.7	7.2	11.3	18.4
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	8.2	-3.9	4.3	2.2	0.5	2.7
Technical Revisions	4.4	-3.3	1.2	0.7	1.8	2.6
Acquisition	0.0	0.0	0.0	16.9	7.9	24.9
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0
Production	-12.2	0.0	-12.2	-0.8	0.0	-0.8
December 31, 2024	**404.4**	**804.6**	**1209.0**	**26.3**	**21.5**	**47.8**

Factors	Conventional Natural Gas Gross Proved Reserves (Bcf)	Conventional Natural Gas Gross Probable Reserves (Bcf)	Conventional Natural Gas Gross Proved + Probable Reserves (Bcf)	Shale Gas Gross Proved Reserves (Bcf)	Shale Gas Gross Probable Reserves (Bcf)	Shale Gas Gross Proved + Probable Reserves (Bcf)
December 31, 2023	0.1	0.0	0.2	17.3	21.6	38.8
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.0	0.0	0.0	5.5	1.3	6.8
Technical Revisions	-0.1	0.0	-0.1	2.2	4.0	6.1
Acquisition	0.0	0.0	0.0	38.7	17.9	56.6
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	-0.2	0.0	-0.3
Production	0.0	0.0	0.0	-1.7	0.0	-1.7
December 31, 2024	**0.1**	**0.0**	**0.1**	**61.9**	**44.7**	**106.5**

Factors	Natural Gas Liquids Gross Proved Reserves (MMbbl)	Natural Gas Liquids Gross Probable Reserves (MMbbl)	Natural Gas Liquids Gross Proved + Probable Reserves (MMbbl)	Oil Equivalent Gross Proved Reserves (MMboe)	Oil Equivalent Gross Probable Reserves (MMboe)	Oil Equivalent Gross Proved + Probable Reserves (MMboe)
December 31, 2023	1.1	1.4	2.5	415.2	828.0	1243.1
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.4	0.1	0.5	11.8	-3.1	8.7
Technical Revisions	0.2	0.4	0.6	5.8	-0.4	5.4
Acquisition	2.7	1.0	3.7	26.0	12.0	38.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	-0.1	0.0	-0.1
Production	-0.1	0.0	-0.1	-13.4	0.0	-13.4
December 31, 2024	**4.3**	**2.9**	**7.2**	**445.3**	**836.4**	**1281.7**

Notes:

(1) Based on the Independent Report. Future net revenue estimates were calculated by McDaniel using the pricing assumptions set forth below under "*Price Forecast*" to ensure for consistency and in accordance with the COGE Handbook.

(2) Totals may not add due to rounding.

(3) All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. For further detail on what is and is not included in abandonment and reclamation costs, please see "*Abandonment and Reclamation Obligations for Properties with Reserves*" below.

(4) The estimated tax burden included in the after-tax net present values of the Company's oil and gas properties is reflected at the corporate consolidation level and does not consider tax planning or provide an estimate of the tax burden at the business entity level which may be significantly different.

(5) Including by-products but excluding solution gas.

(6) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on the Company's Net Reserves.

(7) Light/Medium Crude Oil has been combined with Tight Oil for reporting purposes. Tight Oil accounts for greater than 99% of the reported volumes in this category as of December 31, 2024.

(8) All reserves presented herein represent Athabasca's and Athabasca's consolidated subsidiaries interest. For illustrative purposes, where indicated, values referred to as "Shareholders of Parent" represent 70% of the value attributable to Duvernay Energy as corresponding to Athabasca's 70% equity interest therein, with the values referred to as "Non-Controlling Interests" reflecting the remainder. See "*Statement of Reserves Data – Independent Report"* for more information.

(9) The Acquisition volumes noted in the Consolidated Reconciliation of Reserves by Principal Product Type table are the segregated volumes booked in 2024 on Duvernay Energy's 100% owned land.

Price Forecast

The price forecast ("**Price Forecast**") that formed the basis for McDaniel's revenue projections and net present value estimates is based on a price deck that averages the McDaniel, GLJ and Sproule January 1, 2025 price forecasts. A summary of the Price Forecast is set forth below.

Year	Inflation %	Exchange Rate US$/C$	WTI Crude Oil US$/bbl	Edmonton Light Crude Oil C$/bbl	Western Canadian Select Crude Oil C$/bbl	US Henry Hub Gas US$/MMBtu	AECO Spot Gas C$/MMBtu	Pentanes Plus Edmonton C$/bbl	Butane Edmonton C$/bbl	Propane Edmonton C$/bbl
2025	0	0.712	$71.58	$94.79	$82.69	$3.31	$2.36	$100.14	$51.15	$33.56
2026	2	0.728	$74.48	$97.04	$84.27	$3.73	$3.33	$100.72	$49.99	$32.78
2027	2	0.743	$75.81	$97.37	$83.81	$3.85	$3.48	$100.24	$50.16	$32.81
2028	2	0.743	$77.66	$99.80	$85.70	$3.93	$3.69	$102.73	$51.41	$33.63
2029	2	0.743	$79.22	$101.79	$87.45	$4.01	$3.76	$104.79	$52.44	$34.30
2030	2	0.743	$80.80	$103.83	$89.25	$4.09	$3.83	$106.86	$53.49	$34.99
2031	2	0.743	$82.42	$105.91	$91.04	$4.17	$3.91	$109.01	$54.56	$35.69
2032	2	0.743	$84.06	$108.03	$92.85	$4.26	$3.99	$111.19	$55.65	$36.40
2033	2	0.743	$85.74	$110.19	$94.71	$4.34	$4.07	$113.42	$56.76	$37.13
2034	2	0.743	$87.46	$112.39	$96.61	$4.43	$4.15	$115.69	$57.90	$37.87
2035	2	0.743	$89.21	$114.64	$98.54	$4.52	$4.23	$118.00	$59.05	$38.63
2036	2	0.743	$90.99	$116.93	$100.51	$4.61	$4.32	$120.36	$60.24	$39.40
2037	2	0.743	$92.81	$119.27	$102.52	$4.70	$4.40	$122.77	$61.44	$40.19
2038	2	0.743	$94.67	$121.65	$104.57	$4.79	$4.49	$125.23	$62.67	$41.00
2039	2	0.743	$96.56	$124.09	$106.66	$4.89	$4.58	$127.73	$63.92	$41.82
Thereafter	2	0.743	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

The weighted average realized sales prices for Athabasca for the year ended December 31, 2024 were $71.15/bbl for bitumen, $95.31/bbl for tight oil and light/medium crude oil, $1.68/Mcf for conventional natural gas, $31.83/bbl for NGL and $1.49/Mcf for shale gas.

Undeveloped Reserves

Bitumen

At Leismer and Hangingstone, proved reserves are assigned to lands inside the approved development areas. These areas also contain sufficient stratigraphic drilling to demonstrate with a high degree of certainty the presence of bitumen in commercially recoverable volumes. McDaniel's standard for sufficient drilling in a fluvial SAGD formation is a minimum of eight stratigraphic wells per section with 3D seismic or 16 stratigraphic wells per section with no seismic. The proved undeveloped bitumen reserves attributed to the Leismer Project and Hangingstone Project will transition to proved developed reserves with the drilling and start-up of sustaining wells.

At Leismer and Hangingstone, probable undeveloped reserves are assigned to lands outside the development areas where the Company has firm development intent with sufficient levels of delineation. The lands assigned probable reserves are in close proximity to the initial developments and contain sufficient drilling of stratigraphic wells to establish reservoir suitability for SAGD. McDaniel's standard for probable reserves is a minimum of four stratigraphic wells per section. The probable undeveloped bitumen reserves attributed to Leismer and Hangingstone will transition to proved developed reserves with the drilling and start-up of additional sustaining wells.

At Corner, probable undeveloped reserves are assigned within the development area based on current regulatory approval, firm development intent, and sufficient levels of delineation. The probable undeveloped bitumen reserves attributed to Corner will transition to proved developed reserves with the sanctioning, construction and commissioning of the Corner Project.

In the case of both proved and probable undeveloped reserves, the number of well pairs drilled is limited by the available steam capacity. This is the main factor in determining the development timetable, and since the lifetime of a steam plant exceeds that of a well pair, the majority of the proved and probable undeveloped reserves are expected to be developed beyond two years.

Athabasca's undeveloped bitumen reserves, which are considered to be longer term opportunities, are expected to be developed over the next several decades. For additional information regarding projects that have undeveloped bitumen reserves, see "*Description of Our Business – Our Development Strategy for Our Principal Properties – Athabasca (Thermal Oil)*".

Duvernay Energy

In accordance with NI 51-101, the Independent Report and the reserves data for Athabasca's consolidated reserves, includes (unless otherwise indicated) 100% of the reserves and future net revenue attributable to Duvernay Energy's properties, without reduction to reflect the 30% minority interest of Cenovus in Duvernay Energy. Duvernay Energy's reserve data reflects its 30% net working interest in the Kaybob JDA with Murphy. See "*Statement of Reserves Data – Independent Report*" and "*Description of Our Business – Our Development Strategy for Our Principal Properties – Duvernay Energy"*.

In July of 2023 Athabasca divested its Placid Montney asset that included 98 proved plus probable locations (as at December 31,2022). Light Oil's undeveloped reserves now reside entirely within the Duvernay Energy's asset with 87 proved undeveloped locations and 85 probable undeveloped locations for a total of 172 booked locations.

Proved reserves in the Duvernay Energy asset are scheduled for development within five years. Proved locations are located on both non-operated lands reflecting the five-year development plan which has been approved with our operating partner under the Kaybob JDA and Duvernay Energy's five-year development plan on 100% working interest lands.

Probable locations are scheduled for development after proved locations and are scheduled for development within ten years. Probable reserves do not require any infrastructure or facility expansions. Development in the Kaybob Duvernay has been ongoing since 2011 with management estimates of approximately 444 gross (204 net) remaining locations for development.

General

Athabasca's development plans have been designed to be funded within adjusted funds flow in the current commodity price environment.

A number of factors that impact the timing of our development plans and that may result in accelerated, delayed or cancelled development plans are as follows:

- changing economic conditions (i.e., due to pricing, operating and capital expenditure fluctuations);
- transportation and marketing issues (i.e., availability of diluent, access to market for production due to pipeline delays or unavailability of rail transportation);
- changing technical conditions (i.e., production anomalies, such as water breakthrough or accelerated depletion);
- multi-zone developments (i.e., prospective formation completion may be delayed until the initial completion is no longer economic);
- availability and allocation of capital based on other opportunities available to Athabasca in any given year;
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization;
- surface access issues (i.e., landowner issues, weather conditions and receipt of required regulatory approvals);
- supply chain constraints; and
- changes in the legal and regulatory framework applicable to the assets (i.e., rendering it uneconomic, difficult or impossible to proceed with development).

The following tables set out the volumes of proved undeveloped reserves and probable undeveloped reserves that were attributed for each of Athabasca's product types for each of Athabasca's most recent three financial years using forecast prices and costs:

Gross Proved Undeveloped Consolidated Reserves[(1)(2)(3(4))]

	Bitumen (MMbbl)		Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
2022	0.0	337.5	0.0	0.0	1.5	7.8
2023	0.0	326.6	0.0	0.0	0.4	0.6
2024	**8.2**	**330.4**	**0.0**	**0.0**	**3.0**	**3.6**

	Tight Oil & Light/Medium Crude Oil (MMbbl)		Shale Gas (Bcf)		Oil Equivalent (MMboe)	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
2022	0.2	0.8	9.4	49.9	3.2	354.4
2023	3.1	4.7	6.8	9.9	4.7	333.6
2024	**19.0**	**22.9**	**43.8**	**52.5**	**37.6**	**365.7**

For notes, please see the notes following the "*Gross Probable Undeveloped Reserves*" table.

Gross Probable Undeveloped Consolidated Reserves[(1)(2)(3(4))]

	Bitumen (MMbbl)		Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
2022	0.0	808.4	0.0	0.0	0.0	12.3
2023	0.0	801.3	0.0	0.0	0.1	1.3
2024	**0.0**	**795.1**	**0.0**	**0.0**	**1.1**	**2.8**

	Tight Oil & Light/Medium Crude Oil (MMbbl)		Shale Gas (Bcf)		Oil Equivalent (MMboe)	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
2022	0.0	11.2	0.0	89.5	0.0	846.8
2023	0.5	10.6	1.2	19.7	0.8	816.4
2024	**8.4**	**20.7**	**19.1**	**42.6**	**12.7**	**825.7**

Notes:

(1) "First Attributed" refers to the initial allocation of an undeveloped volume of reserves by the Company for the corresponding financial year.

(2) Based on the Independent Report.

(3) Light/Medium Crude Oil has been combined with Tight Oil for reporting purposes. Tight Oil accounts for greater than 99% of the reported volumes in this category as of December 31, 2024.

(4) All reserves presented herein represent Athabasca's and Athabasca's consolidated subsidiaries interest. See "*Statement of Reserves Data – Independent Report*" for more information.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserves estimates and the present worth of the future net revenue therefrom. See "*Risk Factors – Reserves*".

As circumstances change and additional data becomes available, reserve estimates may also change. Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions may be required as a result of a number of factors that are beyond Athabasca's control, including, among others, product pricing, economic conditions, access to markets, changes to royalty and tax regimes, governmental restrictions, changing operating and capital costs, surface access issues, the receipt of regulatory approvals, availability of services and processing facilities and technical issues affecting well performance. Although every reasonable effort is made to ensure that reserves estimates are accurate, reserve estimation is an inferential science and revisions to reserve estimates based upon the foregoing factors may be either positive or negative.

Consolidated Abandonment and Reclamation Obligations for Properties with Reserves

In connection with Athabasca's operations, Athabasca will incur abandonment and reclamation costs for surface leases, wells and associated pads with proved and probable reserves, interconnecting flowlines, trunk lines, central processing facilities and all related infrastructure facilities and pipelines. Athabasca budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. Athabasca's overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These costs were estimated using, among other things, Athabasca's experience conducting abandonment and reclamation programs, previous actual costs incurred and published industry information. Athabasca reviews suspended or standing wells for reactivation, recompletion or sale and conducts systematic abandonment programs for those wells that do not meet its criteria. A portion of Athabasca's liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of Athabasca's liability reduction programs take into account seasonal access, high priority and stakeholder issues, requirements of applicable laws and opportunities for multi-location programs to reduce costs. There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves.

The future net revenues disclosed in this Annual Information Form are based on the Independent Report and contain an allowance for abandonment and reclamation costs for wells and facilities with reserves associated with the Duvernay Energy, Leismer, Hangingstone and Corner assets. The future net revenue disclosures contained in the Independent Report also includes reclamation and abandonment costs associated with future development wells and facilities which were not included in the Company's consolidated financial statements. The Independent Report deducted an aggregate of $1.1 billion (undiscounted) and $79 million (10% discount) for abandonment and reclamation costs of wells and facilities with proved and probable reserves.

Consolidated Future Development Costs**(1)(2)**

The following table sets forth the undiscounted development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the Independent Report.

Year	Total Proved Reserves Future Development Costs (MM$)	Total Proved Plus Probable Reserves Future Development Costs (MM$)
2025	$179	$262
2026	$257	$470
2027	$284	$663
2028	$318	$1,024
2029	$307	$773
Total for all remaining years	$3,192	$13,295
Total Undiscounted	$4,538	$16,486

Note:
(1) Totals may not add due to rounding
(2) Includes 100% of the values attributable to Duvernay Energy. See "*Statement of Reserves Data – Independent Report*" for more information.

Athabasca expects to fund the development costs of its reserves through cash flow from operating activities and existing cash and cash equivalents. There can be no guarantee that funds will be available or that the Board will allocate funding to develop all of the reserves attributed in the Independent Report. Failure to develop those reserves could have a negative impact on Athabasca's future net revenue relative to the estimates provided herein. See "*Risk Factors – Ability to Finance Capital Requirements*" for additional information.

OTHER OIL AND GAS INFORMATION

Oil & Gas Properties

As of December 31, 2024, Athabasca held approximately 779,000 net acres of mineral resource leases, licenses and permits. This includes over 350,000 net acres of oil sands leases and permits and 310,000 net acres of petroleum and natural gas leases in the Athabasca region of northeastern Alberta and over 98,000 net acres of petroleum and natural gas leases in northwestern Alberta.

Oil sands leases in the Athabasca oil sands area carry a primary term of 15 years. At expiry, an application for continuation requires the agreement holder to outline the lands they intend to continue. Lessees may apply for continuation of all, or a portion, of their lease holdings. The designation of a continued lease can be producing, or non-producing. Operators that choose to keep non-producing continued leases may hold these leases indefinitely, subject to the payment of escalating rent. Petroleum and natural gas leases carry a primary term of five years, after which time the leases can be continued if certain evaluation activity and/or production levels are satisfied. Petroleum and natural gas licenses have a primary term of four years in Northern Alberta and depending on the level of activity and/or production, petroleum and natural gas licenses can be converted into leases at the end of their terms. A vast majority of Athabasca's oil sands reserves and resources are held under the oil sands leases and those lands can be continued indefinitely, subject to the payment of escalating rent.

See "*Description of Our Business – Our Development Strategy for Our Principal Properties – Athabasca (Thermal Oil)*" and "*Description of Our Business – Our Development Strategy for Our Principal Properties – Duvernay Energy*". Athabasca's oil sands leases and permits are large and generally contiguous, which management expects will allow for scale efficiency and simpler development planning.

As of December 31, 2024, Athabasca had an interest in approximately 184 gross wells (131.5 net wells), as set forth below, all of which are located in Alberta:

	Producing		Non-Producing[3]		Total	
	Gross Wells[1]	Net Wells[2]	Gross Wells[1]	Net Wells[2]	Gross Wells[1]	Net Wells[2]
Bitumen[4]	86	86	15	15	101	101
Crude Oil Wells	30	9	2	0.6	32	9.6
Natural Gas Wells	47	16.9	4	4	51	20.9
Total	**163**	**111.9**	**21**	**19.6**	**184**	**131.5**

Notes:

(1) "**Gross Wells**" means the total number of producing or non-producing bitumen, oil or gas wells in which Athabasca had an interest as of December 31, 2024.

(2) "**Net Wells**" means the aggregate number of producing or non-producing bitumen, oil or gas wells obtained by multiplying each Gross Well by Athabasca's percentage working interest therein.

(3) "**Non-Producing**" means wells that are capable of production but were not producing as of December 31, 2024 due to facility limitations, wells where drilling has finished but the well has not been completed, wells waiting to be tied-in, and wells requiring maintenance or workovers where the resumption of production is not known. Non-producing wells do not include wells in the Liege area that are suspended or permanently shut-in either due to a lack of existing functional proximate transportation infrastructure or a permanent shut-in order issued by the AER, its heater assembly facility, water source, steam injection, disposal wells or wells that have been abandoned.

(4) SAGD well pairs are each counted as one well.

Athabasca has a working interest in a total of 67 gross stratigraphic test wells (60.4 net), 173 gross observation wells (172.4 net), and six gross disposal wells (4.3 net). Additionally, Athabasca has 195 gross (150.9 net) wells that are suspended or permanently shut-in. These wells did not produce in 2024.

Properties With No Attributed Reserves

The following table is a summary of properties located in Alberta in which Athabasca has an interest to which no reserves have been attributed, and also the number of net acres for which Athabasca's rights to explore, develop or exploit may, absent further action, expire within one year, as of December 31, 2024:

	Gross Acres(1)	Net Acres(2) (3)	Net Acres Expiring Within One Year(2)
Alberta	510,237	482,437	1,024
Total	**510,237**	**482,437**	1,024

Notes:
(1) "**Gross**" means the total area of properties in which Athabasca has a working interest.
(2) "**Net**" means the total area in which Athabasca has an interest multiplied by the working interest owned by Athabasca.

Significant Factors and Uncertainties Relevant to Properties with No Attributed Reserves

We continually review the economic viability of our undeveloped properties using industry-standard economic evaluation techniques and pricing and economic assumptions. Each year as part of this process, some properties may be selected for further development activities while others may be held in abeyance, sold or relinquished back to the mineral rights owner. There is no guarantee that commercial reserves will be discovered or developed on these properties.

Athabasca has booked $122.6 million of abandonment and reclamation costs inflated at 2.0% and discounted at a rate ranging from 7.0% - 8.0% within its current and long-term provisions ($392.5 million undiscounted). These costs reflect the Company's assets with attributed reserves along with assets with no attributed reserves.

Costs Incurred During the Year Ended December 31, 2024(1)

Division	Proved Property Acquisition Costs MM($)	Unproved Property Acquisition Costs MM($)	Exploration Costs MM($)	Development Costs MM($)
Duvernay Energy	-	-	-	73.1
Thermal Oil	-	-	3.1	192.2
Total	-	-	3.1	265.3

Note:
(1) Does not include costs incurred on corporate assets as set out in the Company's financial statements. In addition, securities in Duvernay Energy were issued to Cenovus in exchange for $94.3 million in petroleum and natural gas assets. See Note 6 in the Company's consolidated financial statements for the year ended December 31, 2024 for more information.

Exploration and Development Activities(1)

The following table summarizes the gross and net exploratory and development wells that were completed by the Company during the year ended December 31, 2024:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	-	-	-	-	-	-
Bitumen wells	-	-	16	16	16	16
Gas wells	-	-	8	5.9	8	5.9
Service wells	-	-	12	12	12	12
Stratigraphic test wells	-	-	-	-	-	-
Dry holes	-	-	-	-	-	-
Total	-	-	36	33.9	36	33.9

Note:
(1) Wells are considered completed as at the rig-release date for such well.

For a description of the Company's current and likely exploration and development activities see "*Description of Our Business*".

Production Estimates[(1)(2)]

The following table sets out the volumes of Athabasca's working interest production estimated by McDaniel for the year ending December 31, 2025, which is reflected in the estimates of future net revenue disclosed in the tables contained under the headings "*Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2024*", "*Future Net Revenue (Undiscounted) – Forecast Prices and Cost as of December 31, 2024*" and "*Future Net Revenue by Product Type – Forecast Prices and Costs as of December 31, 2024*".

Reserve Category	Bitumen Gross bbl/d	Tight Oil & Light/Medium Crude Oil bbl/d	Conventional Natural Gas mcf/d	Shale Gas mcf/d	Natural Gas Liquids bbl/d	Total Oil Equivalent Equivalents boe/d
GROSS PROVED RESERVES						
Leismer	26,459	0	0	0	0	26,459
Hangingstone	7,375	0	0	0	0	7,375
Duvernay Energy	0	2,835	0	6,022	415	4,254
Total	**33,834**	**2,835**	**0**	**6,022**	**415**	**38,088**
GROSS PROBABLE RESERVES						
Leismer	850	0	0	0	0	850
Hangingstone	375	0	0	0	0	375
Duvernay Energy	0	83	0	121	8	111
Total	**1,225**	**83**	**0**	**121**	**8**	**1,337**

Note:
(1) Totals may not add due to rounding
(2) Includes 100% of the values attributable to Duvernay Energy. See "*Statement of Reserves Data – Independent Report*" for more information.

The Leismer assets and Hangingstone assets are estimated to account for greater than 88% of Athabasca's 2025 production volumes on a gross proved reserves basis. As is shown above, estimated 2025 production volumes for the Leismer assets are 26,459 bbl/d of bitumen on a gross proved reserves basis and 27,310 bbl/d of bitumen on a gross proved plus probable reserves basis and estimated production volumes for the Hangingstone assets are 7,375 bbl/d of bitumen on a gross proved reserves basis and 7,750 bbl/d of bitumen on a gross proved plus probable reserves basis. Of the total gross proved 2025 production volumes of 38,088 boe/d less than 4% (1,276 boe/d) represents the non-controlling equity interest in Duvernay Energy held by Cenovus.

Production History[(1)(2)(3)(4)(5)]

The following table sets forth on a quarterly basis for the year ended December 31, 2024, certain information in respect of production, product prices received, royalties paid, production costs and the resulting netbacks.

	Quarter Ended 2024				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2024
Average Daily Production[(1)]					
Bitumen (bbl/d)	31,536	33,765	34,853	33,849	33,505
Tight Oil, and light/medium crude oil (bbl/d)	1,205	2,806	2,688	2,103	2,202
Conventional Natural Gas (Mcf/d)	35	28	27	20	27
NGLs (bbl/d)	180	266	447	422	329
Shale Gas (Mcf/d)	3,256	4,678	5,499	5,152	4,650
Total (Boe/d)	33,470	37,621	38,909	37,236	36,815
Average Prices Received[(2)]					
Bitumen ($/bbl)	61.96	80.36	73.65	67.52	71.15
Tight Oil, and light/medium crude oil ($/bbl)	92.32	99.47	93.29	94.09	95.31
Conventional Natural Gas ($/Mcf)	2.64	1.47	0.70	1.60	1.68
NGLs ($/bbl)	34.73	32.26	31.08	31.14	31.83
Shale Gas ($/Mcf)	2.82	1.32	0.74	1.63	1.49
Total ($/boe)	62.18	79.93	72.90	67.27	70.92
Royalties Paid					
Bitumen ($/bbl)	(4.18)	(9.37)	(6.77)	(4.01)	(6.14)
Tight Oil, and light/medium crude oil ($/bbl)	(22.02)	(0.16)	(12.48)	(13.41)	(14.45)
Conventional Natural Gas ($/Mcf)	(0.04)	1.24	1.95	0.25	0.82
NGLs ($/bbl)	(9.46)	(5.67)	(4.70)	(6.23)	(6.03)
Shale Gas ($/Mcf)	0.79	0.44	1.59	0.17	0.77
Total ($/boe)	(4.71)	(9.43)	(6.75)	(4.45)	(6.41)

	Quarter Ended 2024				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2024
Production Costs(3)(4)					
Bitumen ($/bbl)	(21.42)	(18.40)	(17.20)	(17.21)	(18.47)
Tight Oil, and light/medium crude oil ($/bbl)	(24.45)	(14.26)	(14.78)	(17.44)	(16.75)
Conventional Natural Gas ($/Mcf)	(4.38)	(2.57)	(2.70)	(3.16)	(3.07)
NGLs ($/bbl)	(31.42)	(18.12)	(18.03)	(19.86)	(20.23)
Shale Gas ($/Mcf)	(4.44)	(2.58)	(2.70)	(3.16)	(3.03)
Total ($/boe)	(21.69)	(18.04)	(17.03)	(17.29)	(18.37)
Netback Received(1)(4)					
Bitumen ($/bbl)	36.36	52.59	49.68	46.30	46.54
Tight Oil, and light/medium crude oil ($/bbl)	45.85	85.05	66.03	63.24	64.11
Conventional Natural Gas ($/Mcf)	(1.78)	0.14	(0.05)	(1.31)	(0.57)
NGLs ($/bbl)	(6.15)	8.47	8.35	(5.05)	5.57
Shale Gas ($/Mcf)	(0.83)	(0.82)	(0.37)	(1.36)	(0.77)
Realized gain (loss) on commodity risk management contracts ($/boe)	0.49	(0.46)	(1.21)	(0.56)	(0.48)
Total ($/boe)	36.27	52.00	47.91	44.97	45.66

Notes:

(1) Production and netback figures have been presented by accounting month. The netback figures on a per barrel basis have been calculated on sales volumes. Tight Oil accounts for greater than 99% of the reported volumes in the "tight oil, and light/medium crude oil" category as of December 31, 2024.

(2) Average realized price received for bitumen has been presented net of the cost of the blended diluent sold.

(3) For wells producing multiple products, production costs have been allocated based on barrels of oil equivalent.

(4) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

(5) Includes 100% of the values attributable to Duvernay Energy. See "*Statement of Reserves Data – Independent Report*" for more information.

The following table sets forth the average daily production from each of the Company's producing fields for the year ended December 31, 2024:

	Bitumen (bbl/d)	Tight Oil, and light/medium crude oil (bbl/d)	Conventional Natural Gas (Mcf/d)	NGLs (bbl/d)	Shale Gas (Mcf/d)	Total Oil Equivalent (boe/d)
Leismer area	26,103	-	-	-	-	26,103
Hangingstone area	7,402	-	-	-	-	7,402
Greater Kaybob area	-	2,202	27	329	4,650	3,310
Total	33,505	2,202	27	329	4,650	36,815

Forward Contracts

From time to time, we enter into financial derivatives to manage our exposure to fluctuations in commodity prices, foreign exchange and interest rates. A description of such instruments is provided in Note 10 of the Company's Annual Consolidated Financial Statements and accompanying Management's Discussion and Analysis for the year ended December 31, 2024 and which can be found on the Company's SEDAR+ profile at www.sedarplus.ca.

Tax Horizon

At December 31, 2024, Athabasca recognized a deferred tax asset of $307.3 million and paid no income tax in 2024. Athabasca does not expect to pay Canadian income taxes during the next seven years under the commodity price forecasts in its annual reserves evaluation.

At December 31, 2024, Duvernay Energy recognized a deferred tax liability of $42.6 million as a result of the assets transferred in the Transaction. At December 31, 2024, Duvernay Energy is taxable with an expected current income tax payable calculated at the Canadian statutory tax rate of 23.0% of $2.7 million.

These estimates could be affected by, among other factors, income tax reassessments, a significant change in commodity prices or capital activity or the Company's other business activities such as any joint venture arrangements, acquisitions or asset sales. Changes in these factors from estimates used by the Company could result in the Company paying income taxes earlier or later than expected. For additional information concerning the Company's tax horizon see "*Risk Factors – Income Tax*".

Environmental Considerations

The environmental issues and stakeholder concerns to be managed by Athabasca in developing its assets are similar to those currently being managed by other oil and gas companies, and by communities, and encompass the health of local and regional residents and employees, surface disturbance, effects on traditional land use and historical resources, local and regional air quality, GHG emissions and associated carbon taxes, water quality, monitoring seismic activity levels, health of the aquatic ecosystem in rivers and cumulative effects on wildlife populations and aquatic resources. Athabasca has committed to both site-specific and regional monitoring programs to track the effects of its projects and the cumulative effects of regional development on environmental components and ecosystems.

Athabasca is committed to operating its projects to achieve compliance with applicable statutes, regulations, codes, regulatory approvals and, to the extent practicable, government guidelines. Where the applicable laws are not clear or do not address all environmental concerns, management intends to apply appropriate internal standards and guidelines to address such concerns. In addition to complying with applicable statutes, regulations, codes and regulatory approvals and exercising due diligence, Athabasca strives to continuously improve its operations to address environmental concerns.

DIVIDENDS

Athabasca has not declared or paid any cash dividends on its Common Shares in any of the three most recently completed financial years. Athabasca's management and the Board intend to execute return of capital options for the Company's shareholders as circumstances warrant. Athabasca currently intends to retain future earnings, if any, for future operations, share repurchases or debt repayment. Any decision to declare and pay dividends in the future will be made at the discretion of the Board and will depend on, among other things, results of operations, current and anticipated cash requirements, financial condition, solvency tests imposed by corporate law, contractual restrictions and financing agreement covenants, including those contained in the 2029 Note Indenture and Credit Facility and other factors that the Board may deem relevant.

The terms of the both the Credit Facility and the 2029 Note Indenture contain certain covenants that limit the Company's ability to, among other things, make certain restricted payments including the payment of dividends.

CAPITAL STRUCTURE

General

Athabasca's authorized share capital consists of an unlimited number of Common Shares without nominal or par value, an unlimited number of first preferred shares, issuable in series, and an unlimited number of second preferred shares, issuable in series, each of which are described below. The Company's capital structure includes the 2029 Notes, the Credit Facility, the Unsecured LC Facility, the Duvernay Credit Facility and the Warrants that are described below.

As at December 31, 2024, 517,580,684 Common Shares were issued and outstanding and no first preferred shares or second preferred shares were issued and outstanding. In addition, 2,690,506 Stock Options, 4,377,164 RSUs, 3,251,400 PSUs, 5,283,094 DSUs, and 29,324 Warrants entitling the holders to purchase 6.7 million Common Shares were issued and outstanding on December 31, 2024.

Common Shares

Each Common Share entitles the holder thereof to: vote at any meeting of Shareholders of the Company; receive any dividend on the Common Shares declared by the Company; and receive the remaining property of the Company upon dissolution.

Preferred Shares

Subject to the filing of articles of amendment in accordance with the ABCA, the Board may at any time and from time to time issue first or second preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the Board. Subject to the filing of articles of amendment in accordance with the ABCA, the Board may from time to time fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of first or second preferred shares including, without limiting the generality of the foregoing: the amount, if any, specified as being payable preferentially to such series on a Distribution (as defined below); the extent, if any, of further participation on a Distribution; voting rights, if any; and dividend rights (including whether such dividends are preferential, cumulative or non-cumulative), if any.

In the event of the voluntary or involuntary liquidation, dissolution or winding up of the Company, or any other distribution of its assets among its Shareholders for the purpose of winding up its affairs (such event referred to herein as a "**Distribution**"), holders of each series of first preferred shares shall be entitled, in priority to holders of Common Shares, second preferred shares and any other shares of the Company ranking junior to the first preferred shares from time to time with respect to payment on a Distribution, to be paid rateably with holders of each other series of first preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a Distribution.

The 2029 Note Indenture and Credit Facility contain certain restrictions around restricted payments and the issuance of disqualified stock which may limit the Company's ability to issue first or second preferred shares.

Shareholder Rights Plan

Athabasca's current Shareholder Rights Plan was originally approved by Shareholders at the annual general and special meeting that was held on April 6, 2018, further amended at the annual general and special meeting that was held on May 5, 2021, and further amended and restated at the annual general and special meeting that was held on May 9, 2024 (the "**Amended Rights Plan**"). On May 9, 2024, the Shareholders reconfirmed the Amended Rights Plan for a further three years until the 2027 annual general meeting.

The objectives of the Amended Rights Plan are to ensure, to the extent possible: (a) that all holders of the Common Shares are treated fairly in connection with any unsolicited take-over bid; and (b) the Board has a sufficient opportunity to identify, solicit, develop and negotiate value-enhancing alternatives, as considered appropriate, to any unsolicited take-over bid. The Amended Rights Plan is similar to plans adopted by other Canadian companies.

The Amended Rights Plan encourages a potential acquirer who makes a take-over bid to proceed either by way of a permitted bid, which generally requires a take-over bid to satisfy certain minimum standards designed to promote fairness, or with the concurrence of the Board. If a take-over bid fails to meet these minimum standards, the Amended Rights Plan provides that holders of Common Shares, other than the acquirer, will be able to purchase additional Common Shares at a significant discount to market, thus exposing the acquirer to substantial dilution of its holdings.

A copy of the Amended Rights Plan is available on the Company's SEDAR+ profile at www.sedarplus.ca.

2029 Notes

On August 9, 2024, Athabasca fully repaid its existing US$157 million ($215.6 million) of 2026 Notes using the net proceeds of $195.5 million from the August 9, 2024 issuance of its new $200 million aggregate principal amount of 2029 Notes and cash on hand. The 2029 Notes bear interest at 6.75% per annum, payable semi-annually, and have a term of 5 years maturing on August 9, 2029.

The 2029 Notes are unsecured, ranking equal in right of payment to all existing and future unsecured indebtedness, and are not subject to any maintenance or financial covenants. The indenture governing the 2029 Notes (the "**2029 Note Indenture**") contains certain covenants that limit the Company's ability to, among other things, incur additional indebtedness, create or permit liens to exist, and make certain restricted payments, dispositions and transfers of assets.

Athabasca may redeem all or part of the 2029 Notes at any time prior to August 9, 2026 at 100% of the principal amount plus an applicable premium, as set out in the 2029 Note Indenture. On or after August 9, 2026, Athabasca may redeem all or part of the 2029 Notes at 103.375% from August 9, 2026 to August 8, 2027, at 101.688% from August 9, 2027 to August 8, 2028, and at 100% from August 9, 2028 onwards.

A copy of the 2029 Note Indenture is available on the Company's SEDAR+ profile at www.sedarplus.ca.

Revolving Senior Secured Credit Facility

Athabasca has a $110.0 million reserve-based credit facility (the "**Credit Facility**"). The Credit Facility is a committed facility available on a revolving basis until May 31, 2025, at which point in time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amounts outstanding would be repayable at the end of the non-revolving term being May 31, 2026. The Credit Facility is subject to a semi-annual borrowing base review, occurring by May 31 and November 30 of each year. In the fourth quarter of 2024, the semi-annual borrowing base review was completed and the borrowing base was confirmed at $110.0 million. The borrowing base is determined based on the lenders' evaluation of the Company's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal.

The Credit Facility is secured by a first priority security interest on all present and after acquired property of the Company and is senior in priority to the 2029 Notes. The Credit Facility contains certain covenants that limit the Company's ability to, among other things, incur additional indebtedness, create or permit liens to exist, make certain restricted payments, and dispose of or transfer assets.

As at December 31, 2024, the Company had no amounts drawn and $41.1 million of letters of credit issued and outstanding under the Credit Facility.

LC Facility

Athabasca maintains a $75.0 million unsecured letter of credit facility (the "Unsecured LC Facility") with a Canadian bank that is supported by a performance security guarantee from Export Development Canada. The facility is available on a demand basis and letters of credit issued under this facility incur an issuance and performance guarantee fee. As at December 31, 2024, the Company had $56.4 million of letters of credit issued and outstanding under the Unsecured LC Facility.

Duvernay Energy Credit Facility

Duvernay Energy has a $50.0 million reserve-based credit facility (the "**Duvernay Credit Facility**"). The Duvernay Credit Facility is a committed facility available on a revolving basis until November 30, 2025, at which point in time it may be extended at the lender's option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and any amounts outstanding would be repayable at the end of the non-revolving term, being November 30, 2026. The Duvernay Credit Facility is subject to a semi-annual borrowing base review, occurring by May 31 and November 30 of each year. The borrowing base is determined based on the lender's evaluation of Duvernay Energy's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal.

The Duvernay Credit Facility is secured by a first priority security interest on all present and after acquired property of Duvernay Energy. The Duvernay Credit Facility contains certain covenants that limit the Company's ability to, among other things, incur additional indebtedness, create or permit liens to exist, make certain restricted payments, and dispose of or transfer assets.

As at December 31, 2024, the Company had no amounts drawn and $1.2 million of letters of credit outstanding under the Duvernay Credit Facility.

Warrants

Concurrent with the issuance of the 2026 Notes, Athabasca issued 350,000 warrants, each entitling the holder to purchase 227 Common Shares at an exercise price of $0.9441 per warrant share (the "**Warrants**"), in accordance with the terms and conditions of the warrant indenture dated October 22, 2021 among the Company and Computershare Trust Company of Canada as the warrant agent (the "**Warrant Indenture**"). The Warrants may be exercised at any time prior to 4:00 p.m. (Calgary Time) on November 1, 2026. If the market price of the Common Shares exceeds the exercise price for such Warrants, then a warrant holder may exercise their Warrants on a cashless basis. As at

December 31, 2024, 29,324 Warrants remained outstanding, exercisable for an aggregate of 6.7 million Common Shares (5.5 million Common Shares assuming cashless exercise at December 31, 2024 share price).

CREDIT RATINGS

The following information relating to Athabasca's credit ratings is provided as it relates to Athabasca's financing costs, liquidity and cost of operations. Specifically, credit ratings impact Athabasca's ability to obtain short-term and long-term financing and the cost of such financings. Changes in Athabasca's current credit ratings by its agency, particularly downgrades below the current ratings or negative changes in the ratings outlooks, could adversely affect our cost of borrowing and/or access to sources of liquidity and capital. In addition, changes in credit ratings may affect Athabasca's ability to enter into hedging transactions or other ordinary course contracts on acceptable terms. The Company and its 2029 Notes are currently rated by S&P.

The following table outlines our credit ratings as of December 31, 2024:

	S&P Ratings Services
Corporate Credit Rating	B
2029 Notes	B+
Outlook/Trend	Stable

S&P provide credit ratings of debt securities for commercial entities. A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments. S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative", "stable" or "developing" which assesses the potential direction of a long-term credit rating over the intermediate term (generally up to two years for investment grade and generally up to one year for speculative grade).

A Corporate Credit Rating of B means the issuer currently has the capacity to meet its financial commitments, but adverse business, financial, or economic conditions will likely impair the issuer's capacity or willingness to meet its financial commitments. An issue rating of B indicates that the obligor currently has the capacity to meet its financial commitments on the obligation. However, adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitments on the obligation.

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A rating can be revised, suspended or withdrawn at any time by the rating agency.

Athabasca paid a fee for service to S&P to provide ratings in respect of the 2029 Notes. Otherwise, no service fees other than annual maintenance fees in respect of the existing credit ratings were paid by the Company to S&P during the preceding two years.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares have been listed and posted for trading on the TSX under the symbol "ATH" since April 8, 2010. The following table sets forth the price range and trading volume for the Common Shares on the TSX as reported by the TSX during 2024.

	Price Range		
	High $/share	Low $/share	Volume
December	$5.34	$4.81	41,263,944
November	$5.52	$4.88	46,199,657
October	$5.31	$4.69	58,898,691
September	$5.43	$4.69	76,341,974
August	$5.72	$4.90	46,431,947
July	$5.71	$5.09	52,841,812
June	$5.27	$4.73	60,150,946
May	$5.17	$4.63	72,243,843
April	$5.59	$4.80	85,172,607
March	$5.48	$4.72	74,572,949
February	$4.96	$4.03	61,753,695
January	$4.64	$4.15	58,689,530

Prior Sales

The following is a description of securities of the Company that were issued in the financial year ended December 31, 2024 that are not listed or quoted on a marketplace:

- the Company issued 6,497,369 Common Shares as a result of the exercise and settlement of 6,497,369 Stock Options and RSUs, as applicable;
- the Company granted an aggregate of 1,675,300 RSUs to acquire an aggregate of 1,675,300 Common Shares, each with no exercise price;
- the Company granted an aggregate of 718,500 PSUs to acquire an aggregate of 718,500 Common Shares, each with no exercise price; and
- the Company granted an aggregate of 246,169 DSUs.

DIRECTORS AND OFFICERS

As at the date of filing of this Annual Information Form(5), the names, municipality of residence, positions held with the Company, and principal occupation during the past five years of each of the directors and executive officers of the Company are set out below.

Name and Residence	Position	Principal Occupation During Previous Five Years
Ronald J. Eckhardt(3) Alberta, Canada	Chair and Director Appointed in 2012(1)	Mr. Eckhardt is an independent businessman with over forty-five years of diverse experience in the oil and gas industry including as Executive Vice President, North American Operations of Talisman Energy Inc. Mr. Eckhardt presently also serves on the board of directors of NuVista Energy Ltd.

Name and Residence	Position	Principal Occupation During Previous Five Years
Angela Avery, KC[4] Alberta, Canada	Director Appointed in 2022[1]	Ms. Avery was formerly WestJet's Group Executive Vice President, Chief People, Corporate & Sustainability Officer where she served as an executive officer from February 2020 to December 2024. Ms. Avery has more than 30 years of senior legal and business experience having negotiated transactions exceeding $25 billion. From 2017 to 2020, Ms. Avery held the position of General Counsel and Vice President, Business Development at Athabasca. Prior to that, she was the Chief Compliance Officer for ConocoPhillips' global operations. Her international experience includes an appointment to litigate war reparations with the United Nations. She is called to the bar in Alberta and New York.
Bryan Begley[2][4] Texas, U.S.A.	Director Appointed in 2016[1]	Mr. Begley is an independent businessman. Mr. Begley previously was the Chief Executive Officer of Maroon Peak Energy Resources, LLC and Maroon Peak Management LLC, private companies that owned energy interests in multiple locations. Mr. Begley was also a founder and previous Managing Director of 1901 Partners Management, LP, a private equity firm that managed a portfolio of oil and gas and other energy-related investments. He was also a member of the Board of Directors of Hammerhead Energy Inc. until its sale in 2023. Mr. Begley also previously served as a Managing Director of ZBI Ventures, L.L.C., which he joined in 2007 as part of the founding team, to lead and manage private investments in the energy sector. Prior to joining ZBI Ventures, L.L.C., Mr. Begley was a partner at McKinsey & Co. in the Dallas and Houston offices, where he advised clients across the global energy sector. He has also worked as an engineer with Phillips Petroleum Company in Bartlesville, Oklahoma and Stavanger, Norway.
John Festival[3][4] Alberta, Canada	Director Appointed in 2020[1]	Mr. Festival has over three decades of experience in the oil and gas industry. Mr. Festival is currently President and Chief Executive Officer of Broadview Energy Ltd., a private corporation with heavy oil assets in Alberta and Saskatchewan. Mr. Festival was previously a director of Gibson Energy Inc. from 2018 to 2024, serving as a member on both the Health and Safety Committee and the Sustainability and ESG Committee. From 2009 through 2018, Mr. Festival served as President and Chief Executive Officer of BlackPearl Resources Inc. Prior to that, he served as the President of BlackRock Ventures Inc. from 2001 to 2006 and as its Vice President of Corporate Development from 1999 to 2000. Mr. Festival is currently a director of Cardinal Energy Ltd. and Advantage Energy Ltd.
Marty Proctor[3] Alberta, Canada	Director Appointed in 2022[1]	Mr. Proctor is a seasoned energy executive with more than 35 years' experience in Canada and other international markets. Mr. Proctor held the position of President and Chief Executive Officer of Seven Generations Energy Ltd. from 2017 to 2021 and held the position of President and Chief Operating Officer prior to that from 2014. Mr. Proctor also held the positions of Chief Operating Officer of Baytex Energy Corp. from 2009 to 2014 and Senior Vice President of Upstream Operations with StatoilHydro Canada Ltd. and its predecessor company North American Oil Sands from 2006 to 2009. Mr. Proctor is a director of ARC Resources Ltd., a director of GreenFirst Forest Products Inc., and the Chair of the board of directors of Tenaz Energy Corp. Mr. Proctor holds Bachelor of Science and Master of Science degrees in Petroleum Engineering from the University of Alberta, earned the ICD.D designation from the Institute of Corporate Directors, and is registered as a Professional Engineer with APEGA. In 2022, Mr. Proctor completed the Advanced Management Program at the University of Chicago's Booth School of Business.

Name and Residence	Position	Principal Occupation During Previous Five Years
Marnie Smith[(2)] Alberta, Canada	Director Appointed in 2023[(1)]	Ms. Smith is a Managing Director at Russell Reynolds Associates, a global organizational consulting firm, where she leads the Western Canadian team and Canadian energy platform and is part of the firm's global board and Chief Executive Officer advisory practice. Prior thereto, she served as a Senior Client Partner with Korn Ferry and as Managing Director & Head of Canadian Energy at Macquarie Group. Ms. Smith is a member of the board of directors of Tamarack Valley Energy Ltd. and Shock Trauma Air Rescue Service (STARS).
Theresa Roessel[(2)]	Director Appointed in 2024[(1)]	Ms. Roessel is a finance executive with over 30 years of experience. She is currently the Chief Financial Officer at Canada Diagnostic Centres, where she leads accounting, treasury, planning and risk management. Prior thereto, she served as the Chief Financial Officer for the Calgary Zoo, leading finance, planning, IT, and people services. Previously, Ms. Roessel held the role of Vice President and Controller and other senior finance leadership roles at CNOOC International. Ms. Roessel started her accounting career at Collins Barrow and then Ernst & Young and is a designated CPA, CA. Ms. Roessel is a member of the board of Directors for the Canadian Red Cross and previously served as a Commissioner for the Calgary Police Commission.
Robert Broen Alberta, Canada	Director (Appointed in 2015)[(1)] President & Chief Executive Officer	Mr. Broen has been a director and President and Chief Executive Officer of the Company since April 2015. He previously held the roles of Chief Operating Officer of Athabasca and Senior Vice-President, North American Shale at Talisman Energy Inc. and the President and a director of Talisman Energy USA Inc. Mr. Broen is a Professional Engineer with over 30 years of industry experience and has completed the Executive Education Program at the IVEY School of Business. He is currently on the Board of the Explorers and Producers Association of Canada.
Matthew Taylor Alberta, Canada	Chief Financial Officer	Mr. Taylor has been Chief Financial Officer of the Company since November 6, 2019. Prior thereto, he held the position of Vice President, Capital Markets and Communications of the Company from May 2014. Mr. Taylor was a Director of Energy Equity Research at National Bank and held positions in equity research and investment banking at GMP Securities and CIBC World Markets.
Karla Ingoldsby Alberta, Canada	Vice President, Thermal Oil	Ms. Ingoldsby has been Vice President, Thermal Oil of the Company since January 2018. Previously, Ms. Ingoldsby held progressively more senior roles at the Company including Director Thermal Production, Director New Ventures & Land and Director of Thermal Geosciences, Reservoir & Development. Prior to that, Ms. Ingoldsby held roles at Shell Canada and Royal Dutch Shell Plc.
Cam Danyluk Alberta, Canada	Vice President Business Development & General Counsel	Mr. Danyluk joined the Company as Vice President Business Development & General Counsel in August 2022. Previously he held the position of Vice President, Legal, General Counsel at Total Energy Services Inc. Prior to that he was Vice President, Investment Banking at Mackie Research Capital Corporation and an Associate at Bennett Jones LLP in Calgary.

Name and Residence	Position	Principal Occupation During Previous Five Years
Bruce Beynon Alberta, Canada	Vice President, Light Oil	Mr. Beynon is a professional geologist with over 30 years of oil and gas industry experience. Mr. Beynon joined the Company as Vice President, Light Oil in December 2023. Prior to joining the Company, Mr. Beynon was President of Tiburon Exploration Corp., a private consulting company. Previously, Mr. Beynon was Executive Vice President, Exploration and Corporate Development at Baytex Energy Corporation. Prior to the merger between Baytex and Raging River Exploration, Mr. Beynon held several positions with Raging River including President. Mr. Beynon currently serves as a director and Chair of the board of Southern Energy Corp. and as a director of Lycos Energy Inc.

Notes:

(1) The Company's directors hold office for a term expiring at the conclusion of the next annual meeting of Shareholders of the Company, or until their successors are elected or appointed pursuant to the ABCA and are eligible for re-election. The Company's officers are appointed by and serve at the discretion of the Board.

(2) Member of the Audit Committee. Mr. Begley is the Chair of the Audit Committee.

(3) Member of the Reserves Committee. Mr. Proctor is the Chair of the Reserves Committee.

(4) Member of the Compensation and Governance Committee. Mr. Festival is the Chair of the Compensation and Governance Committee.

(5) The information set forth above is current as at the date of the filing of this Annual Information Form (March 5, 2025).

As at December 31, 2024, the directors and executive officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, an aggregate of 9,371,108 Common Shares, representing approximately 2% of the issued and outstanding Common Shares (not including any Common Shares issuable pursuant to the exercise of the issued and outstanding Stock Options, RSUs or PSUs).

Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the knowledge of the Company, no current director or executive officer of Athabasca has, within the last ten years prior to the date of this document, been a director, chief executive officer or chief financial officer of any issuer (including the Company) that: (a) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (b) was subject to an order that resulted, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

To the knowledge of the Company, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including the Company) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

No current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or security-holder.

To the knowledge of the Company, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Mr. Bryan Begley was the Chair of the Board of Directors of Legend Energy Services, LLC ("**Legend**"), a privately held company in the U.S. which had been one of the horizontal drilling industry's premier coiled tubing service specialists. Upon the downturn in the oil and gas industry, Legend worked together with its secured lender to sell its assets to a smaller operator. To be sure that its remaining assets were shared equitably by its remaining creditors, on October 26, 2021, Legend filed a voluntary Chapter 7 Petition in the United States Bankruptcy Court for the Eastern District of Texas. Mr. Begley ceased his position as a director of Legend on October 26, 2021.

Conflicts of Interest

Certain of Athabasca's directors and officers are engaged in, and may continue to be engaged in, other activities in the oil and natural gas industry from time to time. As a result of these and other activities, certain directors and officers of the Company may become subject to conflicts of interest from time to time. The ABCA provides that in the event that an officer or director is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As at the date hereof, we are not aware of any existing or potential material conflicts of interest between Athabasca or a subsidiary of Athabasca and any our directors or officers.

LEGAL PROCEEDINGS

There are no legal proceedings involving claims for damages for which the potential exposure is more than 10% of our current assets to which we are or were a party, or in respect of which any of our property is or was the subject of, during the most recently completed financial year, nor are there any such material legal proceedings that the Company knows to be contemplated.

During the year ended December 31, 2024, there were: (a) no penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority; (b) no other penalties or sanctions imposed by a court or regulatory body against us that we believe would likely be considered important to a reasonable investor in making an investment decision; and (c) no settlement agreements entered into by us with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as may be disclosed elsewhere in this Annual Information Form, none of our directors, officers or principal shareholders, and no associate or affiliate of any of them, has or has had any material interest in any transaction or any proposed transaction that has materially affected or is reasonably expected to materially affect us or any of our affiliates.

TRANSFER AGENTS AND REGISTRARS

Computershare Trust Company of Canada at its office in Calgary is the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

As at December 31, 2024, the following were the only material contracts, other than those contracts entered into in the ordinary course of business, which the Company or any of its subsidiaries has entered into within the most recently completed financial year, or before the most recently completed financial year and which were still in effect as of December 31, 2024:

- the Amended Rights Plan referred to under the heading "*Capital Structure – Shareholder Rights Plan*";
- the Kaybob JDA (entered into May 13, 2016). See definition of "*Kaybob JDA*";
- the Acquisition Royalty (entered into February 24, 2017). See definition of "*Acquisition Royalty*";
- the Royalty (entered into December 22, 2016). See definition of "*Royalty*";
- the 2029 Note Indenture. See definition "*2029 Note Indenture*"; and
- the Warrant Indenture. See "*Capital Structure – Warrants*".

Copies of these material contracts are available for review on the Company's SEDAR+ profile at www.sedarplus.ca.

INTEREST OF EXPERTS

Names of Experts

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Company during, or relating to the Company's most recently completed financial year other than McDaniel, our independent engineering evaluator, and Ernst & Young LLP, our independent auditor.

Interests of Experts

We used Ernst & Young LLP for external audit services for the fiscal year ended December 31, 2024. Ernst & Young LLP are our auditors and have confirmed that they are independent with respect to us within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

Reserve estimates by McDaniel are included in this Annual Information Form. None of the designated professionals of McDaniel have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associates or affiliates.

AUDIT COMMITTEE

Audit Committee Mandate and Terms of Reference for Chair

The Board's written mandate for the Audit Committee, which sets out the Audit Committee's responsibilities, is attached to this Annual Information Form as Appendix D.

Composition of the Audit Committee and Relevant Education and Experience

The members of our Audit Committee are Bryan Begley (chair), Marnie Smith and Theresa Roessel. Each of the members of the Audit Committee are "independent" and "financially literate" within the meaning of NI 52-110.

Mr. Begley is an independent businessman. Mr. Begley previously was the Chief Executive Officer of Maroon Peak Energy Resources, LLC and Maroon Peak Management LLC, private companies that owned energy interests in multiple locations. Mr. Begley was also a founder and previous Managing Director of 1901 Partners Management, LP, a private equity firm that managed a portfolio of oil and gas and other energy-related investments. He was also a member of the Board of Directors of Hammerhead Energy Inc. until its sale in 2023. Mr. Begley also previously served as a Managing Director of ZBI Ventures, L.L.C., which he joined in 2007 as part of the founding team, to lead and manage private investments in the energy sector. Prior to joining ZBI Ventures, L.L.C., Mr. Begley was a partner at McKinsey

& Co. in the Dallas and Houston offices, where he advised clients across the global energy sector. He has also worked as an engineer with Phillips Petroleum Company in Bartlesville, Oklahoma and Stavanger, Norway.

Ms. Smith is a Managing Director at Russell Reynolds Associates, a global organizational consulting firm, where she leads the Western Canadian team and Canadian energy platform and is part of the firm's global board and Chief Executive Officer advisory practice. Prior thereto, she served as a Senior Client Partner with Korn Ferry and as Managing Director & Head of Canadian Energy at Macquarie Group. Ms. Smith is a member of the board of directors of Tamarack Valley Energy Ltd. and Shock Trauma Air Rescue Service (STARS).

Ms. Roessel is a finance executive with over 30 years of experience. She is currently the Chief Financial Officer at Canada Diagnostic Centres, where she leads accounting, treasury, planning and risk management. Prior thereto, she served as the Chief Financial Officer for the Calgary Zoo, leading finance, planning, IT, and people services. Previously, Ms. Roessel held the role of Vice President and Controller and other senior finance leadership roles at CNOOC International. Ms. Roessel started her accounting career at Collins Barrow and then Ernst & Young and is a designated CPA, CA. Ms. Roessel is a member of the board of Directors for the Canadian Red Cross and previously served as a Commissioner for the Calgary Police Commission.

Audit Committee Oversight

At no time since the commencement of Athabasca's most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by the Board.

Pre-Approval Policies and Procedures for the Engagement of Non-Audit Services

The Audit Committee must pre-approve and disclose, as required, the retention of the external auditor for non-audit services to be provided to the Company or any of its subsidiaries that is permitted under applicable law. In the discretion of the Audit Committee, it may annually delegate to one or more of its independent members or to management the authority to grant pre-approvals for the provision of non-audit services; subject to, in the case of any such delegation to management, the subsequent ratification by the Audit Committee.

Auditors' Fees

The following table summarizes the fees paid by the Company to its auditors, Ernst & Young LLP, for external audit and other services in the last two fiscal years.

Nature of Services	Fees Paid to Auditor in Year Ended December 31, 2024 ($)	Fees Paid to Auditor in Year Ended December 31, 2023 ($)
Audit Fees(1)	491,466	385,000
Audit-Related Fees(2)	20,000	33,000
Tax Fees(3)	56,000	45,000
All Other Fees(4)	-	2,179
Total	**567,466**	**465,179**

Notes:

(1) "**Audit Fees**" means billings for professional services rendered by the issuer's external auditor for the audit and review of the issuer's financial statements or services that are normally provided by the external auditor in connection with statutory and regulatory filings or engagements.

(2) "**Audit-Related Fees**" means billings for assurance and related services that are reasonably related to the performance of the audit or review of the issuer's financial statements, but not reported as audit fees.

(3) "**Tax Fees**" means billings for professional services for tax compliance, tax advice, and tax planning.

(4) "**All Other Fees**" means billings for products or services rendered by the Company's auditor, other than the products and services reported under "Audit Fees", "Audit-Related Fees" and "Tax Fees". All Other Fees paid in the year ended December 31, 2023 relate to Ernst & Young LLP online services.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments in the jurisdictions where the companies have assets or operations. While such regulations do not affect our operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although laws and regulations are a matter of public record, we are unable to predict what additional laws, regulations or amendments governments may enact in the future.

We hold interests in oil and gas properties along with related assets in Alberta. Our assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of our upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Pricing and Marketing

Crude Oil

Producers of crude oil and crude bitumen are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary determinant of oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the imposition of tariffs in jurisdictions in which such products are transported or sold if any and, if appliable, any response thereto, supply/demand balance and contractual terms of sale.

While the trajectory of oil prices continues to be subject to uncertainty and volatility, factors such as transportation disruptions, supply constraints and the conflicts in Ukraine and the Middle East continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "*Industry Conditions – USMCA and Other Trade Agreements*", "*Risk Factors – Political Uncertainty*" and "*Risk Factors – Prices, Markets and Marketing*".

Natural Gas

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, the imposition of tariffs in jurisdictions in which such products are transported or sold if any and, if appliable, any response thereto, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Despite low prices of natural gas in 2024, it is expected that Western Canadian producers will be able to ramp up production ahead of LNG Canada's Kitimat LNG facility coming online, which will be Canada's first large-scale liquified natural gas export facility, expected to start operations in mid-2025. See "*Industry Conditions – USMCA and Other Trade Agreements*", "*Risk Factors – Political Uncertainty*" and "*Risk Factors – Prices, Markets and Marketing*".

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, the imposition of tariffs in jurisdictions in which such products are transported or sold if any and, if appliable, any response thereto, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms. See "*Industry Conditions – USMCA and Other Trade Agreements*", "*Risk Factors – Political Uncertainty*" and "*Risk Factors – Prices, Markets and Marketing*".

Transportation Constraints and Market Access

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and specific substance. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received by producers.

Under the Canadian *Constitution Act, 1867*, the regulation of interprovincial and international pipelines falls within the federal government's jurisdiction and proposed pipeline projects require a regulatory review by the Canada Energy Regulator ("**CER**") and approval by the Canadian federal government ("**Cabinet**") under the *Canadian Energy Regulator Act* (Canada) (the "***CERA***") to proceed. An impact assessment by the Impact Assessment Agency ("**IA Agency**") and a determination by Cabinet that a pipeline project is in the public interest may also be required under the *Impact Assessment Act* (the "***IAA***"). The *CERA* and *IAA* collectively aim to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards.

Nevertheless, regulatory uncertainty at the federal level regarding the approval process for proposed major pipeline projects has impacted certain investment decisions. Even when projects are approved by the Canadian government, such projects often face further delays due to interference by provincial, municipal and, in the case of international pipelines, foreign governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title and a government's duty to consult and accommodate Indigenous peoples.

Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States. With the change of administration in the United States in 2025, the impacts to the regulatory approval regime, changes thereto, if any, and impact on existing actions taken under the prior administration, remain unclear.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects have and are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

Specific Pipeline Updates

Line 5 Tunnel Replacement Project

In December 2023, Michigan Regulators approved Enbridge's Line 5 Tunnel Replacement Project ("**Line 5**"), marking the end of a more than three-year long evaluation process. Line 5 is seen as crucial infrastructure supplying Michigan, Ontario and Québec. This approval begins the process of replacing seven kilometres of the current pipeline with a new underwater tunnel in the Straights of Mackinac. The pipeline will be housed within a concrete tunnel beneath the lakebed. The tunnel project must first be approved by the U.S. Army Corps of Engineers at the United States federal level before construction can commence. The U.S. Army Corps of Engineers has initiated an environmental impact assessment, which is expected to be completed by 2026.

Enbridge has also proposed a 41-mile reroute for Line 5 around the Bad River Band of Lake Superior Chippewa's reservation (the "**Reroute**"). In November 2024, the Wisconsin Department of Natural Resources issued construction permits for the Reroute, a condition of which is that the Reroute must be completed by November 14, 2027.

Trans Mountain Pipeline

Following years of legal and regulatory proceedings, construction challenges and delays, the Trans Mountain Pipeline expansion commenced commercial operations on May 1, 2024, tripling the capacity of the pipeline and adding an additional 590,000 barrels per day of shipping capability. This accounts for 17 percent of the total pipeline export capacity available to Canadian crude oil shippers, according to the CER.

Keystone XL Pipeline

While construction on TC Energy Corporation's ("**TC Energy**") Keystone XL Pipeline (the "**Keystone XL Pipeline**") started in April 2020, the Keystone XL Pipeline remained subject to legal and regulatory barriers in the United States. In 2021, the Biden administration announced its decision to revoke the federal permit granted by the previous administration for the Keystone XL Pipeline. As a result of the revocation and following a comprehensive assessment of its options and consulting with its partners and stakeholders, including the Government of Alberta, on June 9, 2021, TC Energy terminated the Keystone XL Pipeline project.

Since the United States presidential election in the fall of 2024, speculation has arisen that the new administration may revive construction of the Keystone XL Pipeline. However, uncertainty remains as to the advancement of pipeline projects between Canada and the United States amid political uncertainty and as key easements have been returned to landowners in relation to the project.

Marine Tankers

The Oil Tanker Moratorium Act (Canada), imposes a ban on tanker traffic transporting certain crude oil and NGL or persistent crude oil products in excess of 12,500 metric tonnes along British Columbia's north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Natural Gas and LNG

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations.

Development of both provincial and federal net zero frameworks may also impose restrictions on natural gas and LNG projects in Canada, particularly as provincial and federal governments work to achieve emissions reduction targets.

Generally, there are a number of LNG projects (and associated pipelines) proposed or in various stages of development in Canada, although regulatory and legal uncertainty, opposition from environmental and Indigenous groups and changing market conditions have resulted in challenges for many of these projects. Nevertheless, the completion of LNG projects in Canada has the potential to alleviate market access constraints facing natural gas producers in Western Canada and, if completed, may correspondingly increase prices for natural gas produced in Western Canada.

USMCA and Other Trade Agreements

USMCA

The *North American Free Trade Agreement* that previously existed among the governments of Canada, the United States and Mexico was replaced in 2020 by a new trade agreement, widely referred to as the *United States Mexico Canada Agreement* ("***USMCA***") and sometimes referred to as the *Canada United States Mexico Agreement*.

Article 34.7 of the USMCA requires the three signatory countries to hold a joint review of the agreement every six years. The next review is scheduled for July 1, 2026. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGL from Canada, any changes to the USMCA (including as a result of the new administration in the United States) could have an impact on Western Canada's petroleum and natural gas industry at large, including the Company's business.

Other Trade Agreements

Canada has also pursued other international free trade agreements with countries around the world and, as a result, a number of free trade or similar agreements are in force between Canada and certain other countries. Canada agreed to the *Comprehensive Economic and Trade Agreement* ("***CETA***") with the European Union, which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union, although it has not received full ratification by all national legislatures in the European Union.

Following the United Kingdom's departure from the European Union ("**Brexit**") on January 31, 2020, the United Kingdom and Canada agreed to an interim post-Brexit trade agreement, the *Canada-United Kingdom Trade Continuity Agreement* ("***CUKTCA***"). The *CUKTCA* replicates *CETA* on a bilateral basis and is meant to maintain the status quo of the Canada-United Kingdom trade relationship. On January 25, 2024, the United Kingdom formally notified Canada that it had paused negotiations for a new free trade agreement, though the *CUKTCA* remains in force.

Canada and 10 other countries signed the *Comprehensive and Progressive Agreement for Trans-Pacific Partnership* ("***CPTPP***") which allows for preferential market access among its parties. The *CPTPP* is in force among: Canada, Australia, Japan, Mexico, New Zealand, Vietnam, Singapore, Peru, Malaysia, Chile and Brunei Durussalam. As other countries ratify the agreement, they are added to the annexes. The *CPTPP* facilitates temporary entry to Canada for certain categories of business persons who are citizens of other countries which are signatories to the *CPTPP*.

Canada Free Trade Agreement

In August 2023, an updated version of the *Canadian Free Trade Agreement* was published, with the intention to revamp the Agreement on International Trade to create a more robust and equitable trade environment within Canada.

On March 4, 2025, a 25% tariff on all goods originating in Canada and imported into the U.S. and a 10% tariff on “energy and energy resources” from Canada, became effective. In response, the Government of Canada imposed 25% tariffs on an aggregate of $155 billion in goods imported from the U.S., coming into effect in two phases starting on March 4, 2025. The Government of Canada indicated that these measures would remain in place until the U.S. trade action is withdrawn and, in the event that the U.S. tariffs do not cease, further consideration would be given to non-tariff measures against the U.S. A number of provincial governments have also indicated they are actively exploring their own countermeasures to the U.S. tariffs. The implementation of tariffs and/or further retaliatory trade measures, if implemented, could increase the costs for Canadian exporters and may substantially impact the trade relationship between the United States and Canada. See "*Risk Factors – Prices, Markets and Marketing*" and "*Risk Factors – Trade Relations and Tariffs*".

Land Tenure

The respective provincial governments (i.e., the Crown) predominantly own the mineral rights to crude oil and natural gas located in Western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Oil and natural gas leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Additionally, the provinces of Alberta and British Columbia have a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e., freehold mineral lands) also exists in Western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by the federal government on behalf of First Nations or national parks and by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995*. In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. The Company does not have operations on Indian reserve lands.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable typically depends in part on prescribed reference prices, well productivity, geographic location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

Occasionally the governments of Western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the petroleum and natural gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the petroleum and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests, the subject of which are subject to negotiation.

Alberta

In Alberta, the provincially set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. The *Royalty Guarantee Act* (Alberta) came into effect on July 18, 2019 and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

The Modernized Framework applies to all hydrocarbons other than oil sands which remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the AER on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low-cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

Oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly, and producers must submit their records showing the royalty calculation. Under the *Mines and Minerals Act*, producers have three years to amend their royalty calculations before they become statute barred.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula that provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

Oil sands production is also subject to Alberta's royalty regime. The Modernized Framework did not change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for West Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55 per barrel and increase for every dollar of market price of crude oil increase to a maximum of 9% when crude oil is priced at $120 per barrel or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of crude oil increase above $55 up to 40% when crude oil is priced at $120 or higher.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Royalty rates for the production of privately-owned crude oil and natural gas are negotiated between the producer and the resource owner.

Freehold mineral taxes are levied annually for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties. Freehold mineral taxes are in addition to any other negotiated royalty or other payment required to be paid to the owner of such freehold mineral rights.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the freehold mineral owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), freehold mineral taxes or production taxes are levied on the production of crude oil and natural gas from freehold lands in each of the Western Canadian provinces where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in Alberta is included in the above description of the royalty regime.

Where crude oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers, and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

Regulatory Authorities and Environmental Regulation

General

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to water use and conservation, oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition, future changes to legislation and the underlying regulatory requirements, including legislation related to air pollution and GHG emissions, may impose further requirements on operators and other companies in the petroleum and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law generally will prevail. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

Impact Assessment Act

The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CER reviews applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the IA Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency.

Once a review or assessment is commenced under either the *CERA* or *IAA*, there are limits on the amount of time the CER and IA Agency will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process.

Oil Tanker Moratorium Act

On May 12, 2017, the federal government introduced Bill C-48 in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the Oil Tanker Moratorium Act which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53′00′′ north latitude and west of 126°38′36′′ west longitude) and, as a result, may negatively impact the ability of producers to access global markets. Alberta.

Regulatory Framework for the Oil and Gas Sector Greenhouse Gas Emissions Cap

On November 4, 2024, the federal government proposed the Proposed Emissions Cap Regulations. The Proposed Emissions Cap Regulations will establish a cap-and-trade system that will apply to a wide range of industrial activities within the oil and gas sector, including onshore and offshore oil and gas production, oil sands production and upgrading, natural gas production and processing and LNG production. Under the cap-and-trade system, the federal government will determine a maximum threshold for annual emissions and will freely issue emissions allowances in an amount equal to the cap. The initial cap will be based on 2026 emissions (attributed according to a formula set out in the Proposed Emissions Cap Regulations). The cap for the first compliance period, from 2030 to 2032, will be 27% below 2026 attributed emission levels for affected facilities. This reduction is anticipated to correspond to a 35% decrease from 2019 emission levels.

By December 31, 2025, operators of all existing prescribed oil and gas facilities must register with the Department of Environment and Climate Change Canada ("**ECCC**"), submit comprehensive annual emissions reports, and undergo independent third-party verification of its emissions data. This reporting threshold applies broadly across the oil and gas sector, monitoring GHG emissions from facilities with significant outputs. Any operators that do not register would be prohibited from emitting GHGs from their industrial activities unless and until registration is completed.

In addition to the emissions-based reporting threshold, any operator producing at or above an annual threshold of 365,000 boe is classified as a "Covered Operator." Once classified, operators are subject to remittance obligations under the emissions cap framework. Every Covered Operator is required to submit one compliance unit for each tonne of emissions produced. There are three categories of compliance units: (1) emission allowances; (2) decarbonization units; and (3) certain GHG offset credits.

The cap-and-trade system will be phased in over a four-year period from 2026-2029, and so will reporting obligations. Annual reporting requirements involve two separate reports. One report is required for each reporting GHG attributed to the facility and a second report is required that describes the cumulative production of an operator based upon all of its facilities. Operators producing 30,000 or more BOE in any month from the beginning of 2024 to July 2025 or those subject to reporting their GHG emissions in 2024 under a subsection 46(1) *CEPA* notice, must start reporting emissions and production levels for 2026 by June 1, 2027. Operators that do not meet either of these criteria are required to begin reporting through the submission of an annual report no later than by June 1, 2029, for their 2028 emissions and production levels.

This cap-and-trade system has been criticized by provinces and industry on the basis that it amounts to a production cap and could have a material impact on the Company and its and cash flow. However, with the prorogation of federal parliament on January 6, 2025 and federal election to follow, the future applicability and scope of the Proposed Emissions Cap Regulations is uncertain.

Alberta

The AER is the single regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related pieces of legislation including the *Oil and Gas Conservation Act* (the "***OGCA***"), the *Oil Sands Conservation Act*, the *Pipeline Act*, the *Environmental Protection and Enhancement Act*, the *Public Lands Act* and the *Water Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy and Mineral's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for oil and gas development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Protected Areas, the Alberta Ministry of Energy and Minerals, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented. These regional plans may affect further development and operations in such regions.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, increased seismicity induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate crude oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to further investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity is higher, and implemented the requirements in Subsurface Order Nos. 2, 6 and 7. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**"). Crude oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions, and trigger a sliding scale of obligations from the crude oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

On August 14, 2024, Alberta released its Alberta Drought Response Plan (the "**Drought Response Plan**"). The intent of the Drought Response Plan is to ensure Alberta is prepared for the potential of widespread drought. The plan describes preparation, planning and response activities that AEPA will implement to effectively address the full range of possible drought conditions, which may range from localized impacts to multiple river basins simultaneously.

The Drought Response Plan will be led by AEPA and necessitates actions by Alberta Agriculture and Irrigation, Alberta Municipal Affairs, Alberta Forestry and Parks, the AER, and other affiliated ministries.

Liability Management Framework

The AER oversees liability management in the province. Following replacement of Alberta's Liability Management Program ("**AB LMR Program**"), the AER continues to implement its Liability Management Framework ("**AB LMF**"). The primary goals of the AB LMF are to assist in addressing the Orphan Well Association's ("**OWA**") inventory and, creating a framework and regulatory scheme that will better manage site reclamation throughout the lifecycle of a project.

As a result of the Supreme Court of Canada's ("**SCC**") decision in *Orphan Well Association v Grant Thornton Ltd.* (the "***Redwater Decision***"), receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. The *Liabilities Management Statutes Amendment Act* places the burden of a defunct licensees' abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the orphan fund (the "**Orphan Fund**") to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

Alberta's *OGCA* established an Orphan Fund which is run by the OWA to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. The Orphan Fund was originally conceived to be bankrolled exclusively by licensees in the former Alberta Licensee Liability Rating Program (the "**AB LLR Program**") and Alberta Oilfield Waste Liability Program (the "**AB OWL Program**") who contributed to a levy administered by the AER. However, the Government of Alberta has loaned the Orphan Fund approximately $335 million. The Government of Alberta has also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. On March 28, 2024, the AER published *Bulletin 2024-08* prescribing an Orphan Fund Levy of $135 million for the 2024/25 fiscal year. Collectively, these programs were designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. Under the AB LMF, the OWA has broader authority to assist in the reclamation and remediation of wells, facilities or pipelines.

Following the *Redwater Decision*, Alberta committed to actively reducing inventories of orphan and inactive well sites in the province. The AB LMF addresses five key components supporting a lifecycle approach to liability management: (i) practical guidance and support for distressed operators; (ii) a licensee capability assessment system to provide proactive support through ongoing financial capability review; (iii) mandatory spend targets to support inventory reduction; (iv) a process to address legacy and post-closure sites or sites that were remediated, reclaimed or abandoned prior to the AB LMF; and (v) the OWA taking on a more involved role in managing clean-up of oil and natural gas facilities and infrastructure.

On October 8, 2024, the AER announced an invitation for feedback on revised liability directives, specifically considering the potential rescinding of Directive 006: *Licensee Liability Rating Program*, Directive 024: *Large Facility Liability Management Program (LFP)* and Directive 075: *Oilfield Waste Liability (OWL) Program.* Among other changes under the AB LMF, the AB LLR Program and security deposit collection for licence transfer have been replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LLR Program and will establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the AB LMF provides proactive support to distressed operators and requires companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets. Under the AB LMF, each licensee is required to meet mandatory annual spend targets for well closures and abandonments.

Following the public comment period in the fall of 2024, on February 7, 2025, the AER introduced updates to the AB LMF, which took effect immediately upon publication. One of the most notable changes is the removal of the AB LMR Program. In addition, the immediate effects of these regulatory updates on the industry are pronounced in license transfers. The updated framework expands the classification of crossover times for "producer" licensees from three to four categories and generally raises the security ranges across all combinations of financial health and crossover timelines. This suggests a trend toward more stringent security demands for a broader range of transactions, potentially indicating an uptick in the security requirements that will accompany future license transfers.

Pursuant to the AER's inventory reduction program implemented under Directive 088: *Licensee Life-Cycle Management*, licensees are required to meet closure spend requirements aimed at mitigating liabilities associated with inactive and orphan wells. The AER prescribes an industry-wide closure spend requirement each year. A licensee's mandatory closure spend is calculated using a licensee's proportion of industry-wide inactive liability and their level of financial distress determined by the licensee capability assessment. Generally, closure spend rates will be lower for licensees experiencing significant financial distress, and higher for licensees experiencing no financial distress. The industry-wide closure spend requirement for 2024 was set at $700 million, and the 2025 requirement is set at $750 million.

The AB LMF continues to be implemented by the AER with gradual and phasing changes to legislative, regulatory and AER directives required to effectively implement the AB LMF.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada. The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Company and its and cash flow.

International Treaties and Commitments

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. Canada is a signatory to the Paris Agreement, which is committed to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. During the course of the 2021 United Nations Climate Change Conference, Canada pledged to (i) reduce methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) cease to export thermal coal by 2030; (iii) impose a cap on emissions from the oil and gas sector; (iv) halt direct public funding to the global fossil fuel sector by the end of 2022; and (v) commit that all new vehicles sold in the country will be zero-emission on or before 2040. During the 2024 United Nations Climate Change Conference, which concluded on November 22, 2024, nearly 200 countries adopted the New Collective Quantified Goal on climate finance and reached an agreement that will triple financing to developing countries for these initiatives. Canada also committed to international action to reduce methane and industrial GHG emissions.

Federal

The federal government has pledged to cut its emissions by 30% from 2005 levels by 2030; however, it has also indicated that it expects to implement policies to exceed this target. In connection with this target, the federal government released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. In March 2022, the federal government also introduced Canada's 2030 Emissions Reduction Plan (the "**2030 Reduction Plan**"), which provides the building blocks for the Canadian economy to achieve 40% to 45% emissions reductions below 2005 levels by 2030. The 2030 Reduction Plan includes $9.1 billion in new investments as well as carbon pricing and clean fuels measures to assist in growing economic opportunities for a clean future. Progress of the 2030 Reduction Plan will be reviewed and produced in reports in 2023, 2025 and 2027, with additional targets to be developed for 2035 and 2050. On September 4, 2024, the federal government published the 2023 Progress Report. The 2023 Progress Report indicated that Canada is expected to exceed the interim objective of a 20% reduction by 2026.

The federal government's Healthy Environment and a Healthy Economy Plan (the "**HEHE Plan**"), which was adopted in 2021, builds on the Pan-Canadian Framework and provides a roadmap forward to meet Canada's 2030 emissions reduction target. The federal government has agreed to a $8 billion investment over five years to a Net-Zero Accelerator Fund to invest in projects to decarbonize large emitters, scale-up clean technology and otherwise accelerate industry transformation across all sectors. In addition, the HEHE Plan proposes to invest an additional $964 million over four years towards renewable energy and grid modernization projects and $300 million over five years to advance the use of clean and reliable energy in rural, remote and Indigenous communities. The third component of the HEHE Plan pertains to zero emission vehicles. This includes investing an additional $287 million to continue the federal government's Incentives for Zero-Emission Vehicles program until March 2022, $150 million over three years towards charging and refueling stations across Canada, and $1.5 billion towards a Low-Carbon and Zero-Emissions Fuels Fund to increase the production of low-carbon fuels. As of October 1, 2024, to be eligible under the Incentives for Zero-Emission Vehicles program, a vehicle must be made in Canada or in a country that Canada has a free-trade agreement with. Vehicles made in a country where there is no free-trade agreement with Canada may still be eligible if they are already in Canada, or are in transit to Canada prior to October 1, 2024.

Canadian Net-Zero Emissions Accountability Act

Pursuant to Bill C-12, an *Act respecting transparency and accountability in Canada's efforts to achieve net-zero GHG emissions by the year 2050,* Canada joined over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. The *Canadian Net-Zero Emissions Accountability Act* became law in June 2021 and legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation also sets rolling five-year emissions-reduction targets (starting in 2030) and requires emissions reduction plans to reach each target on a reporting basis and enshrines greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

Greenhouse Gas Pollution Pricing Act

Canada's GHG regime is enacted pursuant to the GGPPA, which has two parts: the OBPS and a regulatory fuel charge (the "**Fuel Charge**") imposing an initial price of $20/tonne of carbon dioxide equivalent (CO_2e). This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. In accordance with the HEHE Plan, the price on carbon is set to increase annually at a rate of $15/tonne of CO_2e per year commencing in 2023 through to 2030. The federal government established strengthened minimum national standards (the "**Federal Benchmark**") for 2023 to 2030, which includes the requirement that all jurisdictions establish systems that align with the federal carbon pricing trajectory and benchmark requirements to 2030. The systems will remain until 2027. The minimum carbon pollution price for 2024 is $80/tonne of CO_2e, increasing to $95/tonne of CO_2e on April 1, 2025.

The constitutionality of the *GGPPA* was challenged by several jurisdictions, with the SCC ultimately upholding its constitutionality. Any province or territory has the flexibility to design their own pricing system, so long as it meets the minimum national stringency standards or federal benchmarks. Currently the provincial systems, together with the Fuel Charge apply in each of Alberta, Saskatchewan, Ontario, New Brunswick, Nova Scotia and Newfoundland and Labrador. The provincial plans in each of British Columbia, Québec and the Northwest Territories apply in full in those jurisdictions while the OBPS and Fuel Charge apply in each of Yukon, Nunavut, Manitoba and Prince Edward Island. For so long as the provincial systems in Alberta (under the *Technology Innovation and Emissions Reduction* ("**TIER**") regulation), British Columbia and Saskatchewan meet the federal stringency standards for the emissions they cover, these systems will continue to apply, with the backstop covering those emissions not covered by the provincial systems, as applicable.

Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane

Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

On December 16, 2023 the Government of Canada published draft *Regulations Amending the Regulations Respecting the Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sectors)* for public consultation. The proposed amendments would prohibit flaring and venting, other than to avoid serious risk to human health or safety, at new facilities starting in 2027 and at all facilities in 2030. Alternatively, a facility may install continuous monitoring systems to detect for methane emissions, and then take mandating mitigation measures within set time lines. Further with respect to fugitive emissions, the proposed regulations distinguish between facilities more likely to emit methane from facilities less likely to emit methane. Facilities more likely to emit methane must be inspected quarterly while facilities less likely to emit methane must be inspected annually. Mandatory repair timelines are included in the proposed Regulations upon the detection of an emission. Finally, new equipment standards and mandatory efficiency requirements are proposed in the proposed Regulations.

The draft amendments were open for public consultation until February 14, 2024. The Government of Alberta has opposed the amendments, stating it will take measures to ensure the amended regulations are not implemented in Alberta. It is unknown at this time what the potential effects of the amended Federal Methane Regulations may be.

On March 11, 2024, the Minister of Energy and Natural resources officially launched Canada's Methane Centre of Excellence and a request for proposals for methane mitigation and measurement projects. The Methane Centre of Excellence was instituted as a result of Minister of Environment and Climate Change's announcement of a $30 million investment in December 2023.

Canadian Net-Zero Emissions Accountability Act

In June 2021 the federal government passed the *Canadian Net-Zero Emissions Accountability Act* ("***CNZEAA***"), which provides a legal foundation and framework for Canada to achieve net-zero GHG emissions by 2050. While *CNZEAA* codifies emission targets and planning mechanisms aimed at the federal government, changes to federal government policy and lawmaking regarding the crude oil and natural gas sector can be expected if Canada is to reach its *CNZEAA* targets. The federal government has also introduced new regulations under the *Canadian Environmental Protection Act, 1999* in recent years aimed at incentivising or mandating GHG emission reductions. For example, the federal government introduced the *Clean Fuel Regulations* in 2022, which impose emission reduction obligations on suppliers of liquid fossil fuels beginning in 2023, aiming to spur innovation and economic growth in the low-carbon fuels sector.

Electric Vehicle Regulations

On December 20, 2023 the federal government enacted *Regulations Amending the Passenger Automobile and Light Truck Greenhouse Gas Emissions Regulations* (the "***Electric Vehicle Regulations***") under which automobile manufacturers and importers must meet annual zero-emission vehicle regulated sales targets. Under the *Electric Vehicle Regulations* the target is 20% starting with model year 2026 and then increasing yearly to 100% for model year 2035 and beyond.

Framework to Phase Out Fossil Fuels

On July 24, 2023, the Minister of Environment and Climate Change released the Inefficient Fossil Fuel Subsidies Government of Canada Self-Review Assessment Framework and the Inefficient Fossil Fuel Subsidies Government of Canada Guidelines. The documents will support the federal government's focus on clean energy and net-zero initiatives and the de-carbonization of Canada's oil and gas sector. Pursuant to the framework, subsidies are deemed "inefficient" unless they satisfy certain criteria, which include, but are not limited to: supporting clean energy, clean technology, or renewable energy; providing essential energy service to a remote community; providing short-term support for emergency response; supporting Indigenous economic participation in fossil fuel activities; or supporting abated production processes, such as carbon capture, utilization, and storage, or projects that have a credible plan to achieve net-zero emissions by 2030. The federal government has indicated that it intends to completely phase out inefficient fuel subsidies by 2025. The federal government has proposed a framework for assessing fossil fuel subsidies to identify any potential "inefficient fossil fuel" subsidies. The majority of the subsidies that may be deemed to be inefficient are tax subsidies for the oil and gas sector and the mining sector. The federal government has conducted a preliminary review of various subsidies but has yet to make any concrete decisions respecting the phasing out of such subsidies. With the prorogation of federal parliament on January 6, 2025 and a potential federal election to follow, the future of fuel subsidies is uncertain.

Bill C-59 – Anti-Greenwashing Legislation

In June 2024, Bill C-59, an Act to implement the Fall Economic Statement ("**Bill C-59**"), received royal assent. Bill-C-59 introduced significant updates to the Competition Act with implications for environmental claims and collaborations. The amendments expand the Competition Act's deceptive marketing provisions, requiring businesses making environmental claims about products or business practices to substantiate their statements with "adequate and proper tests" or internationally recognized methodologies. Failure to comply may result in penalties of up to 3% of worldwide revenues and reputational damage. Starting June 20, 2025, private parties will also be allowed to bring deceptive marketing claims before the Competition Tribunal, a right previously reserved to the Competition Bureau. Additionally, Bill C-59 establishes a voluntary pre-approval process for environmental collaborations, allowing businesses to seek certification from the Competition Bureau if their agreements serve environmental goals without significantly reducing competition. However, the requirement to avoid a "substantial prevention or lessening of competition" diverges from more flexible international approaches, potentially limiting its practical utility. The introduction of Bill C-59 increases compliance risks for energy industry participants that make public environmental claims or engage in marketing respecting environmental responsibility.

Alberta

In 2019 the Fuel Charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta is currently $80/tonne of CO2e and will increase to $95/tonne on April 1, 2025. In December 2019, the federal government approved Alberta's TIER regulation, which applies to large emitters and those who have opted-in. The TIER regulation came into effect on January 1, 2020 and replaced the previous Carbon Competitiveness Incentives Regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO_2e per year in 2016 or any subsequent year. Starting in 2020, most TIER-regulated facilities were required to reduce emission intensity by 10%, with an additional 1% annual reduction thereafter. Recent amendments introduced a 2% annual tightening rate for facility-specific and high-performance benchmarks, replacing the previous facility-specific benchmarks for some facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, while facilities with significant prior reductions can use a high-performance benchmark to account for compliance costs. Facilities emitting 2,000 to 10,000 tonnes of CO_2e annually can now opt into the program under amended thresholds. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and, may meet thresholds by either purchasing credits from other facilities, purchasing carbon offsets, or paying a levy to the Government of Alberta. The TIER regulation will continue to apply in Alberta for as long as it meets the federal stringency standards and the federal backstop will apply to the emission sources not covered by the TIER program.

In furtherance of global emissions reductions targets, the Government of Alberta had announced a goal to lower annual methane emissions by 45% by 2025. In November 2023, it was announced that Alberta had achieved its goal of reducing methane emissions by 45%, ahead of schedule.

In May 2020, the federal government and the Government of Alberta announced a preliminary equivalency agreement (the "**Equivalency Agreement**") regarding the reduction of methane emissions. Should amendments to the Federal Methane Regulations come into effect and the Government of Alberta challenges such amendments, the potential effects of such legislation in Alberta, or the effects of any potential challenge to their implementation by the Government of Alberta is unknown.

On November 5, 2021, the Government of Alberta released the Alberta Hydrogen Roadmap, outlining its potential to lead in global and national decarbonization. Phase one focuses on policy, technology investments and supply chain commercialization, while phase two aims to scale production and commercialization.

In February 2023, the TIER regulation was amended to, among other things, amend the opt-in thresholds for emissions-intensive and trade-exposed industries, tighten facility-specific benchmarks, revise the credit use limits and expiration periods as well as create sequestration credits for carbon capture, utilization and storage projects. The TIER regulation will be subject to a subsequent review which must be completed by December 31, 2026.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement CCUS technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund the Quest and Alberta Carbon Trunk Line projects. In 2024, the Government of Alberta announced the Alberta Carbon Capture Incentive Program (the "**ACCIP**") which offers a 12% grant on new eligible CCUS capital costs and is designed to complement the federal incentives. The ACCIP is intended to support Alberta's strategy to stay at the forefront of CCUS development and environmental sustainability.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous communities potentially impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and natural gas industry. In addition, Canada is a signatory to the *United Nations Declaration of the Rights of Indigenous Peoples Act* ("**UNDRIP**") and the principles set forth therein, including the principle to seek free, prior and informed consent, which may continue to influence the role of Indigenous engagement in the development of the oil and natural gas industry in Western Canada. On November 28, 2019, the *Declaration on the Rights of Indigenous Peoples Act* (British Columbia) (the "**DRIPA**") became law in British Columbia. The Government of British Columbia released an interim approach in furtherance of its implementation of DRIPA which outlines a process for how new policy and legislation in the province are to be aligned with UNDRIP. In October 2023, the Northwest Territories passed the *United Nations Declaration on the Rights of Indigenous Peoples Implementation Act* (Northwest Territories) ("**UNDRIPIA**"), becoming the second province or territory to pass legislation to implement UNDRIP in Canada.

Similar to British Columbia's DRIPA, UNDRIP and UNDRIPIA requires the federal government and the Government of the Northwest Territories, respectively, to take all measures necessary to ensure the respective laws of each of Canada and the Northwest Territories are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. The Government of British Columbia released its action plan on March 30, 2022, setting out goals and outcomes that form the long-term vision of implementing UNDRIP in British Columbia. The British Columbia action plan is the first of its kind to be enacted by any province. In 2023, the federal government released the 2023-2028 Action Plan, which sets out a roadmap for advancing reconciliation with Indigenous peoples based on recognition of rights, respect, cooperation, and partnership. In addition, UNDRIPIA requires the Government of the Northwest Territories to co-develop an action plan with Indigenous Governments no later than October 2025. It is uncertain as to what potential consequences the implementation of these action plans and their effects on future legislative drafting may have.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and natural gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. On February 9, 2024, the SCC rendered its decision regarding the *Reference re An Act respecting First Nations, Inuit and Métis children, youth and families*, in which it made clear its opinion that UNDRIP has been incorporated into Canada's domestic positive law.

RISK FACTORS

An investment in our securities is subject to various risks including risks inherent in our industry. If any of the following risks or other risks materialize, our business, prospects, financial condition, results of operations and cash flows could be materially and adversely impacted. The trading price of our securities could decline and investors could lose all or part of their investment in our securities. There is no assurance that risk management steps taken by Athabasca will avoid future loss due to the occurrence of the risk factors described below or other unforeseen risks. Investors should carefully consider the risks described below and the other information contained in this Annual Information Form.

The information set forth below contains forward-looking statements. See "*Forward-Looking Statements*".

Risks Relating to Our Industry and Operations

Weakness in the Oil and Gas Industry

Market events and conditions, including global excess crude oil and natural gas supply, Russia's invasion of Ukraine, war and/or ongoing geopolitical tensions in the Middle East, actions taken by OPEC+, sanctions against, and civil unrest in, Iran and Venezuela, slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, isolationist and punitive trade policies, increased United States shale production, sovereign debt levels, world health emergencies (including the COVID-19 pandemic), climate change concerns and political upheavals in various countries, including growing anti-fossil fuel sentiment, and political uncertainty in Canada and the United States have, at times, caused weakness and volatility in commodity prices in recent years. See "*Risk Factors – Political Uncertainty*".

Following extreme supply/demand imbalance in 2020, the oil and gas industry rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. However, the ongoing wars in the Ukraine and Middle East and price caps and sanctions on oil from Russia have impacted demand and oil prices throughout 2023 and 2024. It is also anticipated that the oil and gas industry will experience more pressure from investors to take meaningful strides towards combating climate change in the upcoming years. See "*Risk Factors – Climate Change and Carbon Pricing Risk*".

These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. Such difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the petroleum and natural gas industry in Western Canada and cross-border with the United States has led to additional downward price pressure on crude oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

Lower commodity prices may also affect the volume and value of our reserves and resources especially as certain reserves and resources become uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, our cash flow resulting in a reduced capital expenditure budget. As a result, Athabasca may not be able to replace its production with additional reserves and both its production and reserves could be reduced on a year over year basis. Any decrease in value of our reserves may reduce the amounts available under the Credit Facility and the Duvernay Credit Facility . Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable terms.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability to find, acquire, develop, commercially produce, transport and sell oil and natural gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able to continue to find satisfactory properties to acquire or participate in. Moreover, Athabasca management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Company will discover or acquire further commercial quantities of crude oil and naturalgas.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife.

Oil and natural gas production operations, including SAGD operations, are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Future crude oil and gas exploration may involve unprofitable efforts, from dry wells or wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completing (including hydraulic fracturing) and operating costs. In addition, drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity, shortages of water for hydraulic fracturing and other operations or other geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Our assets are in relatively early stages exploration or development. There is a risk that the proposed commercial development of our assets will not achieve the expected production levels on the timing anticipated or at all and that the capital costs of such projects will not be within the applicable estimates.

Properties that we decide to drill that do not yield oil, natural gas or NGLs in commercial quantities will adversely affect our results of operations and financial condition. There is no way to conclusively predict in advance of drilling and testing whether any particular well will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

Recovering bitumen from oil sands and upgrading the recovered bitumen into a diluent-bitumen blend product or other products involves particular risks and uncertainties. Our projects will be susceptible to loss of production, slowdowns, or restrictions on our ability to produce higher value products due to the interdependence of the component systems.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas. Our ability to market our oil and natural gas may depend upon our ability to acquire space on pipelines that deliver our production to commercial markets. Deliverability uncertainties related to the distance our reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities, railway blockades as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect us.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC+, the wars between Russia and Ukraine and between Israel and Hamas, governmental regulation, political instability in the Middle East, Northern Africa and elsewhere, impacts on cross-border economic activity (including the imposition of tariffs in jurisdictions in which such products are transported or sold if any and, if applicable, any response thereto), the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, continued economic disruption that may result from the COVID-19 pandemic or other pandemics, and OPEC+'s decisions pertaining to the oil production of OPEC+ member countries, among other factors. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of our reserves. We might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on our carrying value of our reserves, borrowing capacity including available limits under our Credit Facility, revenues, profitability and cash flows from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development projects.

Market Conditions

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, a number of factors, including concerns about effects of the use of fossil fuels on climate change, have affected investor sentiment and some investors have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our reputation, operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which Common Shares will trade cannot be accurately predicted.

Trade Relations and Tariffs

On March 4, 2025, a 25% tariff on all goods originating in Canada and imported into the U.S. and a 10% tariff on “energy and energy resources” from Canada, became effective. In response, the Government of Canada imposed 25% tariffs on an aggregate of $155 billion in goods imported from the U.S., coming into effect in two phases starting on March 4, 2025. The Government of Canada indicated that these measures would remain in place until the U.S. trade action is withdrawn and, in the event that the U.S. tariffs do not cease, further consideration would be given to non-tariff measures against the U.S. A number of provincial governments have also indicated they are actively exploring their own countermeasures to the U.S. tariffs.

Although discussions regarding a potential end to the U.S. tariffs and retaliatory trade measures from Canada are ongoing, the full impact, and duration of such measures remains uncertain. Furthermore, there is a possibility that the trade dispute could escalate further. Additional measures imposed could include, among others, increased tariffs on Canadian energy exports, restrictions on cross-border supply chains, or additional regulatory barriers that could impact our ability to access international markets and conduct business efficiently.

The implementation of tariffs and/or further retaliatory trade measures could have a significant impact on the market for crude oil, NGLs, natural gas and refined petroleum products in Canada and internationally and could result in, among other things, a high degree of both cost and price volatility, a relative weakening of the Canadian dollar, widening differentials, and decreased demand for our products. Any or all of such effects may have a material adverse impact on our business, results of operations and financial condition.

Climate Change and Carbon Pricing Risk

Our exploration and production facilities and other operations and activities, and the products we market, result in the emission of GHGs which makes us subject to GHG emissions legislation and regulations at the provincial and federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the United Nations Framework Convention on Climate Change and a party to the Paris Agreement, the Government of Canada committed to a 40-45% reduction in GHG emissions below 2005 levels by 2030. The Government of Canada made a subsequent commitment in 2021 to achieve net zero emissions by 2050, a commitment that was enshrined in legislation with the passing of *CNZEAA* on June 29, 2021.

One of the pertinent legislative changes to date by the Government of Canada is its implementation of the *GGPPA*, which sets a nationwide benchmark for carbon emissions. The *GGPPA* allows provinces to either develop their own carbon pollution pricing systems that meet the minimum federal benchmark, failing which the federal carbon pollution pricing system applies. The SCC confirmed the Government of Canada's authority to set a price on carbon pollution in provinces and territories that do not systems that meet the federal benchmark in March 2021.

With respect to ESG and climate reporting, on June 26, 2023, the International Sustainability Standards Board issued its first two IFRS Sustainability Disclosure Standards, IFRS S1 - General Requirements for Disclosure of Sustainability-related Financial Information and IFRS S2 - Climate-related Disclosures, with the purpose of developing sustainability disclosure standards that are globally consistent, comparable, transparent and reliable. Similarly, using the IFRS Sustainability Disclosure Standards as a baseline, the Canadian Sustainability Standards Board is developing its own two sustainability disclosure standards modified for the Canadian context, the Canadian Sustainability Disclosure Standard 1 - General Requirements for Disclosure of Sustainability-related Financial Information and Canadian Sustainability Disclosure Standard 2 - Climate-related Disclosures.

In addition, the Canadian Securities Administrators is developing Proposed National Instrument 51-107 – Disclosure of Climate-related Matters, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. It remains unclear if such disclosure requirements will be adopted or, if adopted, the exact nature of the requirements. However, if the Company is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

The direct or indirect costs of compliance with GHG-related legislation and regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change and public discussion that climate change may be associated with extreme weather conditions have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in our profitability and a reduction in the value of our assets or asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Statutes and Regulations Regarding the Environment

Our operations are, and will continue to be, affected in varying degrees by federal and provincial statutes and regulations regarding the protection of the environment. Should there be changes to existing statutes or regulations, our competitive position within the oil sands and petroleum and natural gas industries may be adversely affected, and many industry players have greater resources than us.

Future environmental approvals, laws or regulations may adversely impact our ability to develop and operate our oil sands or light oil projects or increase or maintain production, may increase unit costs of production, or may prevent us from realizing other business opportunities from our exploration leases and permits. Equipment from suppliers which can meet future emission standards may not be available on an economic or timely basis and other methods of reducing emissions to required levels in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation that would tax such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants, which we may be unable to mitigate.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations and requirements to report, investigate and remediate such spill, release or emission. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection, occupational health and safety and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines, penalties and other liabilities, some of which may be material, or the revocation, denial or suspension of permits necessary to our business. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Under certain circumstances, we can have liability for contamination at our facilities even if it arises from third parties or from conduct that was legal at the time it occurred. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

Regulatory Environment and Changes in Applicable Law

The oil and gas industry in Canada, including the oil sands industry, operates under federal and provincial statutes and regulations governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the export of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands, petroleum, natural gas or other interests, the imposition of specific drilling obligations, control over the development and abandonment of oil and natural gas properties (including restrictions on production) and possible expropriation or cancellation of lease and permit rights. The regulatory scheme as it relates to oil sands, and the recovery and marketing of bitumen or bitumen by-products from oil sands, is somewhat different and more burdensome from that related to conventional oil and gas in general.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing statutes or regulations, the implementation of new statutes or regulations or the modification of existing statutes or regulations affecting the crude oil and natural gas industry could impact the markets for crude oil and natural gas, delay or stop the development of our projects, delay or increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects.

In order to conduct oil and gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. The requirements imposed by any such authority may be costly and time-consuming and may delay commencement or continuation of exploration or our production operations. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) which could limit our ability to access external sources of capital and could cause a decrease in the valuation of Canadian companies. Also see "*Industry Conditions - Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*."

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail, some of which we do not own. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. See "*Industry Conditions – Transportation Constraints and Market Access*". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas and could result in our inability to realize the full economic potential of our products or in a reduction of the price offered for our production. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

The impact of the new federal regulatory scheme, including the regime to be implemented under the revised IAA, on proponents and the timing for receipt of approvals of major projects is unknown. Projects which are subject to an impact assessment under both provincial and federal legislation, will likely be subject to a robust assessment of the environmental, social, health, economic and cultural impacts of the proposed project subject to the legislation. In addition, the effects of projects on Indigenous peoples and their constitutionally protected rights may lead to longer periods to conduct the assessment and potentially more opportunities for public engagement and consultation.

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Company's ability to process its production and deliver the same to market. Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Reputation and Public Perception of the Oil and Gas Sector

Development of fossil fuel-based energy, and in particular the Alberta oil sands, has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous reconciliation. Concerns about oil sands may, directly or indirectly, impair the profitability of our current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory, economic and operating uncertainty. Increased public opposition to and stigmatization of the oil and gas sector, and in particular the oil sands industry, could lead to constrained access to insurance, liquidity and capital and changes in demand for our products, which may adversely impact our business, financial condition or results of operations.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard the Company's reputation. Damage to the Company's reputation could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital and decreasing the price and liquidity of the Company's securities.

Environment, Social and Governance Goals

We have set certain ESG goals, and to achieve these goals and to respond to changing market demand, we may incur additional costs and invest in new technologies and innovation. It is possible that the return on these investments may be less than we expect, which may have an adverse effect on our business, financial condition and reputation.

Generally speaking, our ESG goals depend significantly on our ability to execute our current business strategy, which can be impacted by the numerous risks and uncertainties associated with our business and the industry in which we operate, as outlined in this Annual Information Form. We recognize that our ability to adapt to and succeed in a lower-carbon economy will be compared against our peers. Certain investors and stakeholders continue to compare companies based on ESG-related performance, including climate-related performance. Failure to achieve our ESG goals, or a perception among key stakeholders that our ESG goals are insufficient or unattainable, could adversely affect our reputation and our ability to attract capital and insurance coverage.

There is also a risk that some or all of the expected benefits and opportunities of achieving the various ESG goals may fail to materialize, may cost more to achieve or may not occur within the anticipated time periods. In addition, there are risks that the actions we take in implementing targets and ambitions relating to our ESG focus areas may have a negative impact on our existing business and increase capital expenditures, which could have a negative impact on our future operating and financial results.

Political Uncertainty

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely, peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event (including the imposition of tariffs in jurisdictions in which such products are transported or sold if any and, if appliable, any response thereto) could result in a material decline in prices and could have a material adverse effect on Athabasca's results of operations, financial condition and prospects. For instance, in the last several years, the United States, the Middle East, Europe and Latin America have experienced significant political events that have cast uncertainty on global financial and economic markets. See "*Industry Conditions*".

In addition to the risks outlined herein related to geopolitical developments, our oil and natural gas properties, wells and facilities could be subject to public opposition, terrorist attack, blockades or physical sabotage. If any of our properties, wells or facilities are the subject of opposition, terrorist attack, or sabotage it may have a material adverse effect on our business, financial condition, results of operations and prospects. Furthermore, any interruption in the services provided by infrastructure on which Athabasca relies as a result of a terrorist attack would have a material adverse effect. We may not carry insurance to protect against risks arising from terrorism. Future government policies causing broad sweeping lockdowns equivalent to those seen in 2020 as a result of the COVID-19 pandemic could also cause unforeseen interruptions to services or materially impact the delivery scope of services.

A change in federal, provincial or municipal governments in Canada, may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy.

On January 6, 2025, Prime Minister Trudeau requested that federal parliament be prorogued until March 24, 2025. There will be a leadership contest within the current governing Liberal party and a possible federal election shortly thereafter, leading to greater uncertainty within the Canadian political landscape. The future applicability and scope of proposed federal regulations that have not yet been enacted is uncertain. A change in federal government, as well as the new administration in the United States could lead to a policy shift that would impact the oil and gas industry in Western Canada, the effects of which may impact the Company's activities, prospects, financial condition and regulatory environment.

State of the Capital Markets

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of Indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns and government delays concerning market access, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from our Board, management and employees. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in us or not investing in us at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, in us, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares.

Ability to Finance Capital Requirements

Substantial capital expenditures will be required to fund our exploration and development activities. Our 2024 capital and operating budgets were funded with cash flow from operations and existing cash and cash equivalents. In 2025 and beyond, depending on our level of capital spend and the commodity price environment, we may require additional funding which could include debt, equity, joint ventures, asset sales or other financing. The availability of any additional future funding will depend on, among other things, the current commodity price environment, operating performance, our credit rating at the time and the current state of the equity and debt capital markets. A reduction in the current rating on the Company's debt by one or more of its rating agencies or a negative change in the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. There can be no assurance that the cash that may be generated from our operations and/or the other sources of financing, including the ability to raise additional capital through debt financing or refinancing, will be available or sufficient to meet our requirements, or if external sources of funding are available, that they will be available on terms that are acceptable to us. Additionally, asset divestments are subject to certain limitations in terms of how we are permitted to allocate the proceeds pursuant to the terms of the Credit Facility and the 2029 Notes.

Access to Capital and Insurance

Capital markets are adjusting to the risks that climate change poses and as a result, our ability to access capital and secure adequate or prudent insurance coverage may also be adversely affected in the event that investors, credit rating agencies, lenders and/or insurers adopt more restrictive decarbonization policies or through the general stigmatization of the oil and gas industry. Certain insurance companies have taken actions or announced policies to limit available coverage for companies that derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of our insurance policies could increase substantially. In some instances, coverage may be reduced or become unavailable. As a result, we may not be able to renew our existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all. Additionally, certain financial institutions have taken actions or announced policies related to decarbonization of their loan portfolios. As a result, costs of financing could increase over time and we may not be able to refinance our debt, renew or extend credit facilities or procure additional financing at reasonable costs and interest rates, or at all. The future development of our business may be dependent upon our ability to obtain additional capital, including debt and equity financing. See "*Risk Factors – Ability to Finance Capital Requirements*" above.

Abandonment and Reclamation Costs

We will need to comply with the terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of our projects and reclamation of project lands at the end of their economic lives, which will result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of our approvals and such legislation and/or regulations may result in requirements to post financial security with regulators and the imposition of fines and penalties.

It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements. In addition, in the future, we may determine it prudent or be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If Athabasca establishes a reclamation fund, its liquidity and cash flow may be adversely affected.

Changing Demand for Oil and Natural Gas Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. This includes various government regulations that restrict the production and consumption of fossil fuels such as zero emission vehicle mandates, prohibitions on plastic use, and fuel efficiency standards. Government subsidies directed towards new low-carbon technologies or to businesses providing products and services that reduce consumer demand for fossil fuels may also result in a broader reduction in the global economy's reliance on fossil fuels. In addition, shifting consumer preferences towards low-carbon products and services are also driving investment in technologies and products that reduce fossil fuel consumption.

We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Anticipated Benefits of Acquisitions and Dispositions

We consider joint ventures and acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our business and operations. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, certain assets may be periodically disposed of so we can focus our efforts and resources more efficiently. Depending on the state of the market for such assets, certain of our assets, if disposed of, may realize less than their carrying value on our financial statements.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the Western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic. For a discussion of current applicable royalty regimes please see "*Industry Conditions – Royalties and Incentives*".

Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars. The Canadian/U.S. dollar exchange rate, which fluctuates over time, consequently affects the price received by the Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar will negatively affect our production revenues. In the future we may incur U.S. dollar denominated debt which may create exposure to fluctuations in currency exchange rates.

In addition, we may in the future incur indebtedness at variable rates of interest that expose us to additional interest rate risk. If interest rates increase, our debt service obligations on such variable rate indebtedness would increase even though the amount borrowed remains the same, and our net income and cash flows would decrease. This change in interest rate could result in a reduced amount available to fund our exploration and development activities and could negatively impact the market price of the Common Shares. To the extent that we engage in risk management activities related to foreign exchange rates or interest rates, there is a credit risk associated with counterparties with whom we may contract.

Reserves

There are numerous uncertainties inherent in estimating the quantities of reserves and resources attributable to our assets and the future cash flows attributed to such reserves and resources, including many factors beyond our control, and no assurance can be given that the indicated level of reserves and resources and future net revenues will be realized.

In general, estimates of recoverable reserves and resources are based upon a number of factors and assumptions made as of the date on which the reserves and resource estimates were determined, such as geological and engineering estimates, historical production, production rates, well spacing, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, and the assumed effects of regulation by governmental agencies, estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, crude oil and natural gas and the classification of such reserves and resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

In accordance with applicable securities laws, McDaniel used forecast prices and costs in estimating our reserves and future net cash flows as of December 31, 2024. Actual future net cash flows will also be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Our ability to replenish our reserves is important to our long-term viability. Depleted reserves must be replaced by further development of existing sites or by locating new sites in order to maintain production levels over the long term. Resource exploration and development are highly speculative in nature. Our exploration projects involve many risks, require substantial expenditures and may not result in the discovery of sufficient additional deposits that can be extracted profitably. Once a site with deposits is discovered, it may take several years from the initial phases of drilling until production is possible, during which time the economic feasibility of production may change. Substantial expenditures are required to establish recoverable proven and probable reserves and to construct extraction and processing facilities. As a result, there is no assurance that current or future exploration programs will be successful and there is a risk that depletion of reserves will not be offset by discoveries or acquisitions.

Estimates of Contingent Resources are subject to the definitions, disclaimers, contingencies and warnings set forth in "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*". There is no certainty that it will be commercially viable to produce any portion of the resources.

Hedging

The nature of our operations will result in exposure to fluctuations in commodity prices. We use financial instruments and may use physical delivery contracts to hedge our exposure to these risks. In addition, we have previously and may in the future enter into hedging arrangements to act as a risk control mechanism with respect to foreign denominated debt. If product prices increase above those levels specified in any future hedging agreements, we could lose the cost of floors or a fixed price could limit us from receiving the full benefit of commodity price increases. If we enter into hedging arrangements, we may suffer financial loss if we are unable to commence operations on schedule, production falls short of the hedged volumes or prices fall significantly lower than projected, there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement, the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements, a sudden unexpected event materially impacts oil and natural gas prices, or if we are unable to produce sufficient quantities of bitumen, crude oil or natural gas to fulfill our obligations. If currency exchange rates result in a stronger-performing Canadian dollar relative to previously incurred foreign denominated debt, this may result in us incurring financial loss as a result of the financial hedging arrangements we have in place.

Operational Dependence

Other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, we may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, Athabasca potentially becoming subject to additional liabilities relating to such assets and Athabasca having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect our financial and operational results.

Operating Costs

The operating costs of the projects undertaken by us will be significant components of the cost of production of the products produced by such projects. Those operating costs may vary considerably during the operating period. The principal factors which could affect operating costs include, without limitation: the amount and cost of labour to operate the projects; the cost of chemicals; the actual SOR required to operate our oil sands projects; the cost of natural gas, diluent and electricity; the cost of complying with regulatory approvals; the maintenance cost of the facilities; the cost to process product; the cost to transport sales products and the cost to dispose of certain by-products; and the cost of insurance and taxes. Unexpected increases in operating costs may result in decreased earnings, which may in turn have a material adverse effect on our results of operations and financial condition.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Additionally, there is a risk that our future projects may have delays, interruption of operations or increased costs. Our ability to execute projects, and the performance of such projects, is subject to numerous risks beyond our control, including:

- an inability to obtain adequate financing, or financing on terms satisfactory to us;
- shortages of, or delays in, obtaining qualified labour, equipment, materials or services;
- changes in the scope of the project or increases in the amount or cost of materials or labour;
- contractor or operator errors in design or construction and non-performance by, or financial failure of, third-party contractors;
- breakdown or failure of equipment or processes including facility performance falling below expected levels of output or efficiency;
- reservoir performance;
- unforeseen site surface or subsurface conditions;
- the availability of, and the ability to acquire, water supplies needed for drilling, or our ability to dispose of water used or removed from strata at reasonable costs and within applicable environmental regulations;
- disruption in the supply of energy;
- the availability of processing, transportation and storage capacity;
- the effects of inclement weather;
- unexpected cost increases;
- accidental events;
- delays in obtaining required regulatory approvals;
- currency fluctuations;
- regulatory changes;
- environmental and Indigenous activism or land claims that potentially result in delays or cancellations of projects;
- political uncertainty; and
- the regulation of the oil and natural gas industry by various levels of government and agencies.

Because of these factors, we could be unable to execute projects on time, on budget or at all or the projects may not perform to our expectations or as required by regulatory approvals. Any delays may increase the costs of those projects, which could result in the need for additional capital, and there can be no assurance that such capital will be available on acceptable terms or at all.

Supply Chain Disruption

We rely on our supply chain to deliver our products to market. Supply chain impacts are manifesting with rising costs for certain commodities and labour shortages in some areas which can cause cost increases and slower progress than anticipated. Further, the cost or availability of oil and natural gas field equipment may adversely affect our ability to undertake exploration, development and construction projects. The oil and natural gas industry can be cyclical in nature and can be prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects, and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to our operations for the expected price, on the expected timeline, or at all, may have an adverse effect on Athabasca's financial performance and cash flows.

Financial Assurances

We have contracts for pipeline transportation in place with third parties which contain certain financial assurance covenants. Depending upon our capitalization, liquidity position and state of operational performance at certain times, we may not be in a position to comply with the financial assurance covenants contained within these agreements, which may require us to provide security to the third parties we have contracted with including, but not limited to, letters of credit.

Diluent Supply

Bitumen has a high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the processing and transportation of heavy oil and bitumen. A shortage of diluent may cause our costs to increase thereby increasing the cost to transport heavy oil and bitumen to market and increasing our overall operating costs resulting in decreased net revenues and negatively impacting our overall profitability.

Third-Party Credit Risk

We may be exposed to third-party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In addition, we may be exposed to third-party credit risk from operators of properties in which we have a working or royalty interest. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of partners may affect a partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in us being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Indigenous Claims

Indigenous peoples have claimed aboriginal title and rights to portions of Western Canada. We are not aware that any claims have been in respect of our properties or assets. Claims by Indigenous peoples or groups could, among other things, delay or prevent the exploration or development of our properties, which in turn could have a material adverse effect on our business, financial condition, results of operations and prospects.

Reliance on Key Personnel and Operators

Our success depends in large measure on certain key personnel. The loss of or changes in the services provided by such key personnel may have a material adverse effect on its business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. The contributions of the existing management team to our immediate and near-term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Income Tax

Income tax provisions, including current and future income tax assets and liabilities in our financial statements, and income tax filing positions require estimates and interpretations of federal and provincial income tax rules and regulations, and judgments as to their interpretation and application to our specific situation. In addition, there can be no assurance that the Canada Revenue Agency or a provincial or other tax agency will agree with our tax filing positions or will not change its administrative practices to our detriment. Our business and operations are complex and we have executed a number of significant financings, acquisitions, dispositions, reorganizations, joint ventures and business combinations. The computation of income taxes payable as a result of these transactions involves many complex factors as well as our interpretation of and compliance with relevant tax legislation and regulations. While we believe that our tax filing positions are supportable under applicable law, a number of our tax filing positions are or may be the subject of review by taxation authorities. Income tax laws relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects us. Therefore, it is possible that additional taxes could be payable by us and the ultimate value of our income tax assets and liabilities could change in the future and that such additional taxes and changes to such amounts could be materially adverse to us.

Cybersecurity

Athabasca's operations may be negatively impacted by a cybersecurity incident. We use forms of information technology in our operations and such use creates cybersecurity threats including the possibility of potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. Although we have taken various steps to protect ourselves against such risks, the efforts may not always be successful. In the event of a cybersecurity incident, our operations could be disrupted resulting in a material adverse effect on our business, financial condition and results of operations.

In addition, the rapid emergence and continuous evolution of generative artificial intelligence tools may exacerbate Athabasca's technology, information systems and data privacy-related risks due to its potential for user misuse, biased decision-making or unauthorized exposure of the Company's sensitive data.

Advanced Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be affected adversely and materially. If we are unable to utilize the most advanced commercially available technology, our business, financial condition and results of operations could also be adversely affected in a material way.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements or amendments to or stricter interpretation or enforcement of existing laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third-party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Seismic events are common in certain parts of Alberta and are generally clustered around the municipalities of Red Deer, Cardston, Fox Creek and Rocky Mountain House. Due to notable seismic activity reported around Fox Creek and the Red Deer region, the AER introduced seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay formation in the Fox Creek area in February 2015 and subsequently in the Red Deer region in December 2019. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events and the suspension of operations if a seismic event above a particular threshold occurs. These requirements remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Liability Management

Alberta has developed a liability management program designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligation. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Framework*".

The liability management system may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The impact and consequences of the Supreme Court of Canada in the *Redwater* case on the AER's rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings will continue to evolve as the decision is evaluated and as the AER continues its phased implementation of the new AB LMF.

Seasonality and Weather Conditions

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Global climate change could impact the timing and length of the winter and corresponding spring thaws, which could adversely affect our business and operating results. Furthermore, extreme climate conditions that could result in natural disasters such as flooding, drought or fires, may result in increased expenditures or delays or cancellation of some of our operations.

Additionally, climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. Long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns discussed above. In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require us to incur greater expenditures to address such changes to our operations, which may have a material adverse effect on our results of operations and increased costs to obtain insurance.

Unexpected Events

Operating levels within the oil and gas extraction industry are subject to unexpected conditions and events that are beyond the industry's control. Those events could cause industry members or their suppliers to curtail production or shut down a portion or all of their operations, which could reduce the demand for our products, and could affect adversely our sales, margins and profitability.

Interruptions in production capabilities inevitably will increase our production costs and potentially reduce our profitability. We do not have meaningful excess capacity for current production needs, and we are not able to quickly increase production at one site to offset an interruption in production at another site.

A portion of our production costs are fixed regardless of current operating levels. As noted, our operating levels are subject to conditions beyond our control that can delay deliveries or increase the cost of operation at particular sites for varying lengths of time. These include weather conditions (for example, extreme winter weather, tornadoes, floods, and the lack of availability of process water due to drought) and natural and man-made disasters, wildfires like the Fort McMurray wildfire in 2016, unanticipated geological conditions, including variations in the amount and type of rock and soil overlying the oil or natural gas deposits, variations in rock and other natural materials and variations in geologic conditions.

The processes that take place in our facilities and those facilities owned by third parties through which our production is transported and processed, depend on critical pieces of equipment. This equipment may, on occasion, be out of service because of unanticipated failures. Remediation of any interruption in production capability may require us to make large capital expenditures that could have a negative effect on our profitability and cash flows. Our business interruption insurance would not cover all or any of the lost revenues associated with equipment failures. Longer-term business disruptions could result in a loss of customers, which adversely could affect our future sales levels and, therefore, our profitability.

Internal Controls

Effective internal controls are necessary for us to provide reliable financial reports and to help prevent fraud. Although we undertake a number of procedures in order to help ensure the reliability of our financial reports, including those imposed on us under Canadian securities laws, we cannot be certain that such measures will ensure that we will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm our results of operations or cause us to fail to meet our reporting obligations. If we or our independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in our consolidated financial statements and harm the trading price of the Common Shares.

Evolving Corporate Governance, Sustainability and Reporting Framework

The Company's business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of noncompliance, which could have an adverse effect on the price of the Company's securities. The Company is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities Administrators, the TSX and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity making compliance more difficult and uncertain. Further, the Company's efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

Limitations of Insurance

Our involvement in the exploration for and development of oil, natural gas and bitumen properties may result in us becoming subject to liability for pollution, blowouts, leaks of sour gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. Our property, business interruption and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these and other insurable risks. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Litigation

In the normal course of our operations, we are or we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land rights, environmental issues, including claims relating to contamination or natural resource damages, and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from our business operations, which could adversely affect our financial condition.

In recent years there has been an increase in climate change related demands, disputes, and litigation in various jurisdictions including Canada, asserting various claims, including that oil producers contribute to climate change, that such entities are not reasonably managing business risks associated with climate change, and that such entities have not adequately disclosed business risks of climate change. While many of the climate change related actions are in preliminary stages of litigation, and in some cases assert novel or untested causes of action, there can be no assurance that legal, societal, scientific and political developments will not increase the likelihood of successful climate change related litigation against oil producers, including Athabasca. The outcome of any such litigation is uncertain and may materially impact our business, financial condition or results of operations. We may also be subject to adverse publicity associated with such matters, which may negatively affect public perception and our reputation, regardless of whether we are ultimately found responsible. We may be required to incur significant expenses or devote significant resources in defense against any such litigation.

Natural Gas Overlying Bitumen Resources

Some of our oil sands leases contain producing and shut-in natural gas wells owned by third parties that may penetrate, or otherwise result in the applicable petroleum and natural gas zones coming into communication with, our bitumen resources. In October 2009, the Energy Resources Conservation Board of Alberta (the "ERCB", now the AER) ordered the interim shut-in of 297 intervals associated with 158 gas wells largely in the Dover West area to mitigate potential future risk to bitumen recovery in the area. On December 15, 2011, pursuant to Order 11-002, the ERCB shut-in these, as well as other wells. There are also natural gas zones in several of our asset areas that do not currently contain producing or shut-in natural gas wells. There is a risk that if the production of natural gas from these zones penetrates or otherwise comes into communication with our bitumen resources, there may be a loss of steam or steam chamber pressure during the SAGD bitumen extraction process, which could adversely affect our ability to recover bitumen using SAGD technology. No assurance can be provided that the production or potential production of natural gas overlying bitumen resources on our oil sands leases will not pose a risk to our ability to recover the bitumen resources on these properties using SAGD technology, and such risk could have a material adverse effect on our business, financial condition, liquidity and results of operations.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the exploration, development, production and marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than us. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than us. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Chain of Title and Expiration of Licenses and Leases

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. Our actual interest in properties may, accordingly, vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes which affect our title to the oil and natural gas properties we control that could impair our activities on them and result in a reduction of the revenue received by us. Moreover, our licenses and leases may terminate or expire and there can be no assurance that any of the obligations required to maintain each license or lease will be met.

Breaches of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

New Industry Related Activities or New Geographical Areas

The operations and expertise of our management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Water Use Restrictions and/or Limited Access to Water

Athabasca undertakes certain hydraulic fracturing and SAGD programs. To undertake such operations the Company needs to have access to sufficient volumes of water, or other liquids. There is no certainty that the Company will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as hydraulic fracturing and SAGD. If the Company is unable to access such water it may not be able to undertake hydraulic fracturing or SAGD, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

Relationship with Duvernay Energy Corporation

Athabasca's 70% ownership of Duvernay Energy is expected to contribute to the growth and success of the Company's business. There are no assurances, however, that the Company will be able to realize the benefits we anticipate from our ownership of Duvernay Energy. If the Company is unable to successfully execute on its business plan as it pertains to Duvernay Energy, the Company's overall growth could be impaired and the Company's operational and financial performance could be lower than expected.

Moreover, certain conflicts of interest could arise as a result of the relationship between Athabasca and Duvernay Energy. Three of Duvernay Energy's four directors hold offices at Athabasca, with one of Duvernay Energy's directors also being a director of Athabasca. In addition, Duvernay Energy will initially be dependent on Athabasca for management, operating, administrative and other services. As a result, the duties of the directors and officers of Athabasca and Duvernay Energy may come into conflict. These conflicts, if any, will be handled in accordance with the ABCA.

In addition, certain of Athabasca's executive management team are also officers of Duvernay Energy. Depending on Duvernay Energy's operational and other demands, this could result in such persons having less time to devote to Athabasca.

Management Estimates and Assumptions

In preparing consolidated financial statements in conformity with IFRS, estimates and assumptions are used by management in determining the reported amounts of assets and liabilities, revenues and expenses recognized during the periods presented and disclosures of contingent assets and liabilities known to exist as of the date of the financial statements. These estimates and assumptions must be made because certain information that is used in the preparation of such financial statements is dependent on future events, cannot be calculated with a high degree of precision from data available, or is not capable of being readily calculated based on generally accepted methodologies. In some cases, these estimates are particularly difficult to determine, and the Company must exercise significant judgment. Estimates may be used in management's assessment of items such as depletion, depreciation and accretion, fair values, useful lives of assets, deferred income taxes, share-based compensation, estimates of reserves, derivative financial instruments, decommissioning obligations, leases and onerous contracts. Actual results for all estimates could differ materially from the estimates and assumptions used by the Company, which could have a material adverse effect on Athabasca's financial condition, results of operations and prospects.

Third-Party Claims

From time to time, the Company may be the subject of litigation arising out of its operations. There is also a risk that Athabasca could face litigation initiated by third parties relating to climate change, including litigation pertaining to GHG emissions, the production, sale or promotion of fossil fuels and petroleum products and/or disclosure. Claims under any such litigation may be material or may be indeterminate. The outcome of such litigation may materially affect Athabasca's financial condition or results from operations. The Company may be required to incur significant expenses or devote significant resources in defense of any litigation.

Conflicts of Interest

Certain of the Company's directors and officers are also directors and officers of other companies and conflicts of interest may arise between their duties as officers and directors of Athabasca and as officers and directors of such other companies. To the extent that such other companies may participate in ventures in which the Company may participate, or in ventures which the Company may seek to participate, the Company's directors and officers may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation and will be subject to and governed by the ABCA. The ABCA requires a director or officer of a corporation who is party to a material contract or proposed material contract with the Company to disclose such director's or officer's interest and, with respect to a director, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. In all cases where the Company's directors and officers have an interest in other companies, such other companies may also compete with the Company for the acquisition of oil and natural gas properties. Such conflicts of the Company's directors and officers may result in a material and adverse effect on the Company's profitability, results of operation and financial condition. As a result of these conflicts of interest, the Company may miss the opportunity to participate.

Inflation and Cost Management

The Company's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. The Company's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on the Company's financial performance and operations.

Credit Ratings

Athabasca could experience downgrades to its credit ratings. In addition, in the event of any significant downgrade, certain of the Company's service providers may require the Company to post incremental collateral or provide other assurances of the Company's ability to perform its obligations under its contracts with such providers, which could negatively affect the Company's financial liquidity. In addition, downgrades to the credit ratings applicable to Athabasca's debt could impact the value, trading prices and liquidity for such debt.

Growth Management

Athabasca may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The Company's ability to manage growth effectively will require it to continue to implement and improve its operations and financial systems and to expand, train and manage its employee base. The Company's inability to deal with this growth could have a material adverse effect on its business, financial condition, results of operations and prospects.

Impact of Pandemics

In the event of a global pandemic, countries around the world may close international borders and order the closure of institutions and businesses deemed non-essential. This could result in a significant reduction in economic activity in Canada and internationally along with a drop in demand for oil and natural gas. Any reduction in economic activity in certain countries resulting from outbreaks, government-imposed lockdowns and other restrictions could have a negative effect on demand for oil and natural gas and could also aggravate the other risk factors identified herein.

Ability of Investors Resident in the United States to Enforce Civil Remedies in Canada

Athabasca is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All but one of our directors, all of our officers, all of our assets, all of our experts, and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the US to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the US. There is doubt as to the enforceability in Canada against the Company or against such persons who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Risks Related to Our Debt and Securities

Level of Indebtedness

Our indebtedness could have important consequences to us, including:

- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of our development plans or other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service the indebtedness;
- increasing our vulnerability to general adverse economic and industry conditions, including increases in interest rates;
- limiting our ability to capitalize on business opportunities and to react to competitive pressures and adverse changes in government regulation; or
- limiting our ability, or increasing the costs, to refinance indebtedness.

Restrictions in Our Debt Instruments

Our debt agreements including the 2029 Notes, Credit Facility and Duvernay Credit Facility include covenants that, among other things, restrict the ability of Athabasca and its subsidiaries to:

- incur indebtedness;
- make restricted payments, including paying dividends and prepaying junior debt;
- make investments;
- create liens;
- sell assets; or
- engage in mergers or acquisitions.

Our failure to comply with these covenants would likely result in an event of default under our debt agreements. Such a default could allow the creditors to accelerate the related indebtedness and result in acceleration of our other indebtedness to which a cross-acceleration or cross-default provision applies. In the event that noteholders accelerate the repayment of our indebtedness, we may not have sufficient assets or be able to borrow sufficient funds to repay or refinance that indebtedness.

The available lending limits of the Credit Facility and the Duvernay Credit Facility are reviewed semi-annually and are based on the lenders' assessment of the Company's reserves and future commodity prices as well as the application of applicable discount rates and other factors by the lenders, including their respective normal petroleum and natural gas lending criteria and practices in effect at the time of such review for loans to borrowers in the Canadian petroleum and natural gas industry. A material decline in commodity prices or the value of our reserves could reduce the available lending limits under the Credit Facility or the Duvernay Credit Facility, therefore reducing the funds available to the Company which could result in a portion, or all, of the Company's indebtedness under the Credit Facility or the Duvernay Credit Facility being required to be repaid. The acceleration of our indebtedness under the Credit Facility or the Duvernay Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions.

If Athabasca experiences certain changes in control, Athabasca may be required to make an offer to repurchase all of the outstanding 2029 Notes prior to their maturity at not less than 101% of their principal amount. Additionally, under the Credit Facility and the Duvernay Credit Facility, certain changes in control may permit the lenders to accelerate the maturity of borrowings under such facilities, terminate their commitments to lend and require repayment of amounts drawn under the Credit Facility or the Duvernay Credit Facility. Athabasca may not have sufficient funds or be able to arrange for additional financing at the time of the change of control to make the required repurchase of the 2029 Notes and repay any of Athabasca's other indebtedness that may also become due.

Additional Indebtedness

Despite our current level of indebtedness, we may still be able to incur substantially more debt, which could further exacerbate the risks associated with our leverage.

Issuance of Additional Securities

The Board may issue an unlimited number of Common Shares, without any vote or action by Athabasca's Shareholders, subject to the rules of the TSX or such other stock exchange on which Athabasca's securities may be listed from time to time. Athabasca may make future acquisitions or enter into financings or other transactions involving the issuance of securities. In addition, Athabasca may issue Stock Options, RSUs, PSUs and other security-based awards exercisable to acquire up to 8% of the number of Common Shares outstanding at any given time. If Athabasca issues any additional Common Shares, the percentage ownership of existing Shareholders will be reduced and diluted.

As a result of the foregoing factors, purchasers of Common Shares may not receive any return on an investment in Common Shares unless they sell such Common Shares for a price greater than that which they paid for it.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on the Company's SEDAR+ profile at www.sedarplus.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of securities and securities authorized for issuance under the Company's equity compensation plans, is contained in the Information Circular for the Company's most recent annual meeting of securityholders that involved the election of directors. Additional financial information about Athabasca is provided in the Company's financial statements and management's discussion and analysis for the year ended December 31, 2024, which may be found on the Company's SEDAR+ profile at www.sedarplus.ca.

GLOSSARY OF DEFINED TERMS

"**2026 Notes**" has the meaning given to such term under the heading "*Development of our Business – Developments in 2024"*.

"**2029 Notes**" has the meaning given to such term under the heading "*Development of our Business – Developments in 2024"*.

"**2029 Note Indenture**" has the meaning given to such term under the heading "*Capital Structure – 2029 Notes*".

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"**Acquisition Royalty**" means the royalty granted by Athabasca to Burgess on February 24, 2017, and upsized on April 28, 2017 and on April 28, 2020, on the Leismer and Corner properties. The Acquisition Royalty is based on a linear scale (0 – 15%) with a WCS benchmark. The minimum 2.5% trigger is US$60/bbl WCS and the Acquisition Royalty is not expected to materially impact the economics of future expansion phases or development projects and there are no associated commitments for development.

"**AER**" means the Alberta Energy Regulator.

"**Amended Rights Plan**" has the meaning given to such term under "*Capital Structure – Shareholder Rights Plan*".

"**API**" refers to an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale.

"**Athabasca**" means "we", "our", "us", or the "Company" or Athabasca Oil Corporation and/or its wholly-owned or controlled subsidiaries, as the context requires.

"**Athabasca (Thermal Oil)**" means Athabasca's business unit which is primarily focused on the exploration for, and sustainable development and production of, bitumen from oil sands.

"**Audit Committee**" means the audit committee of the Board.

"**Best Estimate**" has the meaning given to that term under "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*".

"**bitumen**" means a naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons with a viscosity greater than 10,000 milliPascal seconds (or centipoise) measured at the hydrocarbon's original temperature in the reservoir and atmospheric pressure, on a gas-free basis and is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods. Crude bitumen may contain sulphur and other non-hydrocarbon compounds.

"**Board**" means the Board of Directors of the Company.

"**Burgess**" means Burgess Energy Holdings L.L.C.

"**carbonate**" means a class of sedimentary rock whose chief mineral constituents (95% or more) are calcite, aragonite and dolomite. Limestone, dolostone (or dolomite) and chalk are carbonate rocks. Although carbonate rocks can be clastic in origin, they are more commonly formed through processes of precipitation or the activity of organisms such as coral and algae. Carbonates form in shallow and deep marine settings, evaporitic basins, lakes and windy deserts. Carbonate rocks are common hydrocarbon reservoir rocks.

"**Cenovus**" has the meaning given to such term under "*Development of Our Business – Developments in 2024".*

"**clastic**" means sediment consisting of weathered fragments derived from pre-existing rocks and transported elsewhere and redeposited before forming another rock. Examples of common clastic sedimentary rocks include siliciclastic rocks such as conglomerate, sandstone, siltstone and shale.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter) as amended from time to time.

"**Common Shares**" means the common shares in the capital of the Company, as constituted on the date hereof.

"**Compensation and Governance Committee**" means the compensation and governance committee of the Board.

"**Contingent Resources**" has the meaning given to that term under "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*".

"**conventional natural gas**" means natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

"**Corner assets**" means the interests of Athabasca in approximately 44,000 net acres of oil sands leases (not including overlying petroleum and natural gas leases) located in the Athabasca oil sands fairway in northeastern Alberta (see map at "*Description of Our Business – Our Development Strategy for Our Principal Properties*") as of December 31, 2024, that are more particularly described under "*Description of Our Business – Our Development Strategy for Our Principal Properties – Athabasca (Thermal Oil) – Leismer Corner Assets*" and "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*".

"**Corner Project**" means Corner Project 1 and Corner Project 2.

"**Corner Project 1**" means a SAGD project to be located in the Corner asset area with a production capacity of 40,000 bbl/d.

"**Corner Project 2**" means an expansion of the Corner assets by 50,000 bbl/d of production capacity. This phase will increase the total facility capacity to 90,000 bbl/d.

"**CPF**" means central processing facility.

"**Credit Facility**" has the meaning given to that term under "*Capital Structure – Revolving Senior Secured Credit Facility*".

"**crude oil**" or "**oil**" means a mixture consisting mainly of pentanes and heavier hydrocarbons that exist in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas. Classes of crude are reported on basis of density, acceptable ranges are as follows: Light: less than 870kg/m3 (greater than 31.1 degrees (symbol) API), Medium: 870-920 kg/m3 (31.1-22.3 degrees API), Heavy 920-1000 kg/m3 (22.3-10 degrees API).

"**dilbit**" means a blend of condensate and bitumen.

"**diluent**" means lighter viscosity petroleum products that are used to dilute bitumen for purposes such as transportation in pipelines.

"**Distribution**" has the meaning given to such term under "*Capital Structure – Preferred Shares*".

"**Dover West assets**" means the interests of Athabasca in approximately 149,000 net acres of land as of December 31, 2024 located within the Athabasca oil sands fairway in northeastern Alberta (see map at "*Description of Our*

Business – Our Development Strategy for Our Principal Properties") that are more particularly described under "*Description of Our Business – Our Development Strategy for Our Principal Properties – Thermal Oil Exploration – Dover West Assets*" and "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*".

"**Dover West Sands**" means the clastic bitumen reservoirs contained within the McMurray Formation and the Wabiskaw member of the Clearwater formation in the Dover West assets.

"**Dover West Sands Project**" means a SAGD project in the Dover West area that has three planned phases. Project 1 has a planned production capacity of 20,000 bbl/d, Project 2 increases the total production capacity to 50,000 bbl/d, and Project 3 increases the total production capacity up to 90,000 bbl/d.

"**DSU**" means a deferred share unit granted under the Company's deferred share unit plan which was originally made effective for directors of the Company on March 11, 2015 and as amended from time to time.

"Duvernay Credit Facility" has the meaning given to that term under "*Capital Structure – Duvernay Energy Credit Facility".*

"**Duvernay Energy**" has the meaning given to such term under "*Development of Our Business – Developments in 2024*".

"**Enbridge**" means Enbridge Inc. or any of its subsidiaries.

"**ESG**" has the meaning given to such term under "*Description of our Business – Environmental, Social and Governance Policies*".

"**established technology**" means methods that have been proven to be successful in commercial applications, as such term is defined in the COGE Handbook.

"**forecast prices and costs**" means future prices and costs that are: (a) generally accepted as being a reasonable outlook of the future; or (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Athabasca is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a).

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs.

"**GHG**" means greenhouse gas.

"**gross**" means in relation to reserves: the Company's working interest volumes (operating or non-operating) before deduction of royalties and without including any royalty interests of the Company; in relation to properties: the total area in which the Company has an interest; in relation to wells: the total number of wells the Company has an interest in.

"**Hangingstone assets**" means the interests of Athabasca in approximately 76,000 net acres of land located in the Athabasca oil sands fairway in northeastern Alberta (see map at "*Description of Our Business – Our Development Strategy for Our Principal Properties*") as of December 31, 2024 with up to 12,000 bbl/d producing capacity, that are more particularly described under "*Description of Our Business – Our Development Strategy for Our Principal Properties – Athabasca (Thermal Oil) –Hangingstone Assets*" and "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*".

"**Hangingstone Project**" means a producing SAGD project in the Hangingstone area of northwestern Alberta with plant capacity of 12,000 bbl/d.

"**hydrocarbon**" means a compound consisting of hydrogen and carbon, which, when naturally occurring, may also contain other elements such as sulphur.

"**in-situ**" means "in place" and, when referring to oil sands, means a process for recovering bitumen from oil sands by means other than surface mining, such as SAGD.

"**Independent Report**" means the report prepared by McDaniel dated effective as of December 31, 2024, assessing and evaluating the proved reserves and probable reserves of the Company located in the Leismer, Corner, Hangingstone and Duvernay Energy assets and the Contingent Resources located in the Leismer, Corner and Dover West Sands assets.

"Kaybob JDA" means the joint development agreement between the Company and Murphy dated May 13, 2016**.**

"**Leismer assets**" means the interests of Athabasca in approximately 81,000 net acres of oil sands leases (not including overlying petroleum and natural gas leases) located in the Athabasca oil sands fairway in northeastern Alberta (see map at "*Description of Our Business – Our Development Strategy for Our Principal Properties*") as of December 31, 2024 with up to 80,000 bbl/d producing capacity, that are more particularly described under "*Description of Our Business – Athabasca (Thermal Oil) – Leismer Corner Assets*" and "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*".

"**Leismer Project**" means a producing SAGD project in Northwestern Alberta with a plant capacity up to 28,000 bbl/d.

"**Leismer Project 2**" means an expansion of the Leismer assets by 12,000 bbl/d of production capacity. This phase will increase the total facility capacity to 40,000 bbl/d.

"**Leismer Project 3**" means an expansion phase of the Leismer assets by 40,000 bbl/d of production capacity. This phase will increase the total facility capacity to 80,000 bbl/d.

"**Light Crude Oil**" or "**light crude oil**" means crude oil with a relative density greater than 31.1 degrees API gravity.

"**Light Oil Division**" means Athabasca's former business unit which was primarily focused on the exploration for, and sustainable development and production of, light oil and liquids-rich natural gas. Following closing of the Transaction with Cenovus, the Light Oil Division has been renamed "Duvernay Energy".

"**liquids**" includes tight oil, light and medium crude oil and natural gas liquids.

"**McDaniel**" means McDaniel & Associates Consultants Ltd., an independent qualified reserve and resource evaluator.

"**Medium Crude Oil**" or "**medium crude oil**" means crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

"Murphy" means Murphy Oil Canada Ltd., a wholly owned subsidiary of Murphy Oil Corporation.

"**MM$**" means millions of Canadian dollars.

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases, which may contain sulphur or other non-hydrocarbon compounds.

"**net acres**" means the percentage of total acres an owner owns out of a specific number of acres or specified area.

"**Net Reserves**" means Athabasca's working interest (operating or non-operating) share after deduction of royalty obligations, plus Athabasca's royalty interests in reserves.

"**NGL**" or "**natural gas liquids**" means the hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to ethane, propane, butanes, pentanes plus and condensates.

"**NI 51-101**" means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

"**NI 51-102**" means National Instrument 51-102 *Continuous Disclosure Obligations.*

"**oil sands**" means deposits of sand, sandstone, carbonate or other mineral material containing bitumen.

"**Omnibus Incentive Plan**" means the omnibus incentive plan of the Company which was originally made effective on March 29, 2021, as amended from time to time.

"**permeability**" is a measure of the ability of a rock to conduct a fluid through its interconnected pores when that fluid is at 100% saturation. A rock may be highly porous and yet impermeable if it has no interconnecting pore network (communication). Permeability is measured in darcies or millidarcies.

"**Placid assets**" means the interests of Athabasca in approximately 61,000 net acres of land located primarily in northwestern Alberta. These assets were sold in July of 2023 see under " *Description of our Business – Developments in 2023*".

"**porosity**" means the volume of a rock available to contain fluids; the ratio of void space to the bulk volume of rock containing that void space. Porosity can be expressed as a fraction or percentage of pore volume in a volume of rock.

"**Price Forecast**" has the meaning given to such term under "*Statement of Reserves Data – Reserves Classifications*".

"**PSU**" means a performance share unit granted under the Omnibus Incentive Plan or performance awards granted under the performance award plan of the Company which was originally effective March 18, 2014 and as amended from time to time.

"**Reserves Committee**" means the reserves committee of the Board.

"**reservoir**" means a porous and permeable formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

"**risked**" has the meaning given to that term under "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*".

"**Royalty**" means a contingent bitumen royalty granted to Burgess Energy Holdings L.L.C. on the Company's oilsands assets located at Hangingstone and Dover West on June 20, 2016, and upsized on April 28, 2020. Payment of the applicable royalty rate is tied to US$ WCS benchmark prices and calculated on a linear scale ranging from 0-15% of the Company's realized bitumen price ($C), with the royalty rate beginning at 2.5% when US$ WCS reaches $60/bbl in the case of Hangingstone and $70/bbl in the case of Dover West. The realized price is determined net of diluent, transportation and storage costs and have been structured so that the assets will not be encumbered at lower pricing levels.

"**RSU**" means a restricted share unit granted under the Omnibus Incentive Plan or the restricted share unit plan of the Company originally effective March 11, 2015, as amended from time to time.

"**S&P**" means Standard and Poor's Global Rating Services, a division of S&P Global Inc.

"**SAGD**" means steam assisted gravity drainage, an in-situ process used to recover bitumen from oil sands.

"**saturation**" is the fraction or percentage of the pore volume occupied by a specific fluid (i.e., oil, gas, water, etc.).

"**shale gas**" means natural gas contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay materials and that usually requires the use of hydraulic fracturing to achieve economic production rates.

"**Shareholders**" means the holders, from time to time, of the Common Shares, collectively or individually, as the context requires.

"**SOR**" means steam to oil ratio.

"**Statoil**" means Statoil ASA or Statoil Canada Limited, now Equinor Canada Ltd.

"**Stock Option**" means a stock option granted under the Omnibus Incentive Plan or the stock option plan of the Company originally dated effective as of September 1, 2009, as amended from time to time.

"**technology under development**" means a recovery process or process improvement project that has been determined to be technically viable via a field test and is being field tested further to determine its economic viability in the subject reservoir as such term is defined in the COGE Handbook.

"**Thermal Oil assets**" means the interests of Athabasca in approximately 348,000 net acres of oil sands leases in the Athabasca region of northeastern Alberta, as at December 31, 2024.

"**tight oil**" means crude oil contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily contained in microscopic pore spaces that are poorly connected to one another and that usually requires the use of hydraulic fracturing to achieve economic production rates.

"**Transaction**" has the meaning given to such term under "*Development of Our Business – Developments in 2024*".

"**TSX**" means the Toronto Stock Exchange.

"**unrisked**" has the meaning given to that term under "*Appendix A – Supplemental Disclosure – Contingent Resource Estimates*".

"**Unsecured LC Facility**" has the meaning given to that term under "*Capital Structure – LC Facility*".

"**Warrants**" has the meaning given to that term under "*Capital Structure – Warrants*".

"**Warrant Indenture**" has the meaning given to that term under "*Capital Structure – Warrants*".

"**WCS**" means Western Canadian Select.

"**WTI**" means West Texas Intermediate grade crude oil at a reference sales point in Cushing, Oklahoma, a common benchmark for crude oils.

Certain other terms used herein but not defined herein are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

APPENDIX A

SUPPLEMENTAL DISCLOSURE – CONTINGENT RESOURCE ESTIMATES AS AT DECEMBER 31, 2024

Athabasca engaged McDaniel to prepare Contingent Resource evaluations of its Leismer, Corner, Hangingstone and Dover West Sands assets. All of Athabasca's Contingent Resources have been evaluated in accordance with NI 51-101. McDaniel's Report on Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor is set forth in Appendix C to this Annual Information Form.

Quantities of Contingent Resources may be estimated using Low Estimate (high certainty), Best Estimate (most likely) and High Estimate (low certainty) cases. In this Annual Information Form, Athabasca has reported its Contingent Resources using the Best Estimate case, which is considered to be the best estimate of the quantity of Contingent Resources that may actually be recovered. All of the Company's Contingent Resources disclosed herein are classified under the product type of bitumen resources. It should not be assumed that the estimates of recovery, production and net revenue that are reflected in the table that is provided below represent the fair market value of Athabasca's bitumen resources. There is no assurance that the forecast prices and cost assumptions will be realized and variances could be material and there is no guarantee that the estimated resources will be recovered or produced. Actual resources may be greater than or less than the estimates provided herein. There is no certainty that it will be commercially viable for Athabasca to produce any portion of the Contingent Resources on any of its properties.

The Contingent Resources estimates presented in the Independent Report are based upon the definitions and guidelines contained in the COGE Handbook. A summary of the applicable definitions is set forth below:

"**Best Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

"**chance of development**" means the estimated probability that, once discovered, a known accumulation will be commercially developed.

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

"**Economic**" means those Contingent Resources that are currently economically recoverable based on the same fiscal conditions used in the assessment of reserves.

"**risked**" means the applicable reported volumes or revenues have been risked (or adjusted) based on the chance of commerciality of such resources in accordance with the COGE Handbook. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, risked reported volumes and values of contingent resources reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

"**unrisked**" means applicable reported volumes or values of resources have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, unrisked reported volumes and values of contingent resources do not reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

Contingent Resources may be divided into the following project maturity sub-classes:

"**Development Pending**" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development).

"**Development on Hold**" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

"**Development Not Viable**" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development.

Other terms not defined in this Appendix A have the meaning ascribed to such terms under "*Glossary of Defined Terms*" in the main body of this Annual Information Form.

The following tables set forth: (a) the unrisked Best Estimate Contingent Resources; (b) the risked Best Estimate Contingent Resources; and (c) the associated risked future net revenue (before income taxes) estimates for the Contingent Resources calculated by McDaniel in the Independent Report. The evaluation procedure employed by McDaniel is in accordance with the standards set forth in the COGE Handbook. The price forecasts that formed the basis for the net present value estimates that are contained herein were based on McDaniel's January 1, 2025 pricing models set forth below under "*Forecast Prices & Costs Used in Contingent Resource Estimates*". There is no assurance that the forecast price and cost assumptions used will be realized and variances could be material. See "*Forward Looking Statements*" in this Annual Information Form.

An estimate of risked net present value of future net revenue of Contingent Resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of Athabasca proceeding with the required investment. It includes Contingent Resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Unrisked and Risked Contingent Resources and Risked Net Present Value of Future Net Revenue (Best Estimate Contingent Resources)(1)(2)(3)(4)(5)(6)(7)(8)(9)(10)(11)(12)

							Risked Net Present Value of Future Net Revenue Before Income Tax Discounted at (%/year)				
	Working Interest (%)	Gross Unrisked Best Estimate Contingent Resources (MMbbl)	Chance of Development (%)	Project Maturity Classification	Gross Risked Best Estimate Contingent Resources (MMbbl)	Net Risked Best Estimate Contingent Resources (MMbbl)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
Leismer	100	468	90	Pending	421	276	8,365	2,640	926	307	54
Corner	100	520	80	Pending	416	263	9,556	2,749	828	207	-8
Hangingstone	100	36	70	On-Hold	25	16	694	68	7	1	0
Total:		1,023	84		862	554	18,615	5,457	1,762	515	46

Sub-Economic Resource	Working Interest (%)	Gross Unrisked Best Estimate Contingent Resources (MMbbl)	Chance of Development (%)	Project Maturity Classification	Gross Risked Best Estimate Contingent Resources (MMbbl)
Dover West Sands	100	2,223	20	Not Viable	445
Hangingstone	100	565	20	Not Viable	113
Total:		2,788	20		558

Notes:

(1) See definitions for "Contingent Resources", "Best Estimate", "risked", "unrisked" "Development Pending", "Development on Hold" and "Development Not Viable".

(2) The volumes of Contingent Resources in this table were calculated at the outlet of the proposed extraction plant.

(3) There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

(4) The Contingent Resource estimates set out in the table reflect, as of December 31, 2024, Athabasca's working interest in the Leismer, Corner, Hangingstone and Dover West Sands assets.

(5) Based on the estimates contained in the Independent Report dated effective as of December 31, 2024, calculated by McDaniel using McDaniel's pricing forecasts for consistency and in accordance with the COGE Handbook.

(6) Totals may not add due to rounding.

(7) Gross unrisked Contingent Resource volumes have been included to provide a comparison with the Company's Contingent Resources disclosure from previous years in which risking was not included (prior to 2016).

(8) All of the Company's Contingent Resources are of the bitumen product type.

(9) All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. For a further discussion of what is and isn't included in abandonment and reclamation costs, please see "*Abandonment and Reclamation Costs*" below.

(10) The estimates of Contingent Resources (Best Estimate) and future net revenue for individual properties may not reflect the same confidence levels as estimates of Contingent Resources (Best Estimate) and future net revenues for all properties, due to the effects of aggregation.

(11) The method of quantifying the chance of development is set out in the COGE Handbook Volume 2, Section 2.

(12) The Dover West Sands and portions of the Hangingstone volumes are not economic at this time and are classified accordingly as Not Viable. Further changes in economic conditions or technical development as of the effective date may result in a change to a different sub-classification in the future. The volumes reported in the table are the gross sub-economic technical volumes for the asset.

Forecast Prices & Costs Used in Contingent Resource Estimates

Year	Inflation	Exchange Rate	WTI Crude Oil	Edmonton Light Crude Oil	Western Canadian Select Crude Oil	US Henry Hub Gas	AECO Spot Gas	Pentanes Plus Edmonton	Butane Edmonton	Propane Edmonton
	%	US$/C$	US$/bbl	C$/bbl	C$/bbl	US$/MMBtu	C$/MMBtu	C$/bbl	C$/bbl	C$/bbl
2025	0	0.712	$71.58	$94.79	$82.69	$3.31	$2.36	$100.14	$51.15	$33.56
2026	2	0.728	$74.48	$97.04	$84.27	$3.73	$3.33	$100.72	$49.99	$32.78
2027	2	0.743	$75.81	$97.37	$83.81	$3.85	$3.48	$100.24	$50.16	$32.81
2028	2	0.743	$77.66	$99.80	$85.70	$3.93	$3.69	$102.73	$51.41	$33.63
2029	2	0.743	$79.22	$101.79	$87.45	$4.01	$3.76	$104.79	$52.44	$34.30
2030	2	0.743	$80.80	$103.83	$89.25	$4.09	$3.83	$106.86	$53.49	$34.99
2031	2	0.743	$82.42	$105.91	$91.04	$4.17	$3.91	$109.01	$54.56	$35.69
2032	2	0.743	$84.06	$108.03	$92.85	$4.26	$3.99	$111.19	$55.65	$36.40
2033	2	0.743	$85.74	$110.19	$94.71	$4.34	$4.07	$113.42	$56.76	$37.13
2034	2	0.743	$87.46	$112.39	$96.61	$4.43	$4.15	$115.69	$57.90	$37.87
2035	2	0.743	$89.21	$114.64	$98.54	$4.52	$4.23	$118.00	$59.05	$38.63
2036	2	0.743	$90.99	$116.93	$100.51	$4.61	$4.32	$120.36	$60.24	$39.40
2037	2	0.743	$92.81	$119.27	$102.52	$4.70	$4.40	$122.77	$61.44	$40.19
2038	2	0.743	$94.67	$121.65	$104.57	$4.79	$4.49	$125.23	$62.67	$41.00
2039	2	0.743	$96.56	$124.09	$106.66	$4.89	$4.58	$127.73	$63.92	$41.82
Thereafter	2	0.743	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

Description of Leismer Contingent Resources

The Contingent Resources assigned to Athabasca's Leismer assets assume that such resources will be produced using SAGD technology which has been successfully implemented at the Leismer Project since 2010. The production of Contingent Resources assigned to the Leismer assets is contingent upon the completion of Leismer Project 3 which, if commissioned, is planned to be on stream in 2030 adding an incremental 40,000 bbl/d of capacity to the facility. This would increase the total Leismer plant capacity to 80,000 bbl/d.

A field development plan (a pre-development study) has been developed for the Leismer assets but the existing environmental impact assessment is for capacity of 40,000 bbl/d and an amendment for 80,000 bbl/d has not been submitted to date.

The infrastructure already in place to support Leismer Project 3 includes the access road to the CPF, the diluent import pipeline, capacity on the dilbit sales pipeline to Cheecham, tank capacity at Cheecham and the gas import pipeline. However, the existing pipelines and tankage will require debottlenecking to be able to accept the volumes from Leismer Project 3.

Based on Athabasca's development plan, the total Best Estimate capital cost of first commercial production in 2030 for the Leismer Project 3 is estimated at approximately $1,509 million (uninflated, unrisked, undiscounted) which includes delineation, SAGD well pairs and central processing facilities.

The contingencies identified for the development of the Leismer Contingent Resources are:

- Regulatory Approval – filing an amendment to the existing Leismer application.
- Market Conditions – the Leismer Project 3 is not expected to be sanctioned by the Board until market conditions improve and project funding is secured.
- Delineation – further delineation is required before a final investment decision can be made.
- Firm development plans and detailed cost estimates - have not yet been developed.
- Project Timing – Leismer Project 3 is not anticipated to start up until 2030 and significant spending is not anticipated before 2028.

In accordance with the COGE Handbook, Leismer risked Best Estimate Contingent Resources have been classified as Development Pending by McDaniel. These Contingent Resources are considered to be Development Pending as they are within 10 miles of the existing CPF and there is sufficient delineation to prepare the development strategy consistent with a project evaluation scenario status of development. Athabasca is actively working on this property and there is corporate intent to develop the Contingent Resources in the near term. First steam is planned for 2030 subject to project sanctioning. The Hangingstone Project took 4.5 years from commencing preparation of the regulatory application to first steam. Athabasca will execute the Leismer Project 3 with the same proven execution strategy and facility design and consequently does not need to do further work on the Leismer Project 3 until 2028 to maintain a reasonable expectation of reaching first steam in 2030. The level of economic analysis is sufficient to assess the development options and overall project viability but is insufficient for a final investment decision. The chance of development of these Contingent Resources is estimated to be 90%.

The positive factors relevant to the Contingent Resource estimates for the Leismer Project 3 include:

- They are within a 10 mile radius of the existing CPF and significant infrastructure is already in place.
- Using established technology which is being successfully implemented at the Leismer Project.
- A development plan is in place.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the project maturity sub-class of Development Pending.

The negative factors relevant to the Contingent Resource estimates for the Leismer Project include:

- Economic sensitivity to future oil pricing.
- Existing infrastructure requires debottlenecking.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- The Leismer regulatory application has not yet been amended for Leismer Project 3.

See also "*Risk Factors*" in this Annual Information Form.

Description of Corner Contingent Resources

The Contingent Resources assigned to Athabasca's Corner assets assumes the resources will be produced using SAGD technology which has been successfully implemented in the nearby Leismer Project since 2010. The production of the Contingent Resources assigned to the Corner assets is contingent upon the completion of the second phase which, if commissioned, is planned to be on stream in 2034 with a capacity of 50,000 bbl/d. This would increase the total Corner plant capacity to 90,000 bbl/d.

A field development plan (a pre-development study) has been developed for the Corner assets but the existing environmental impact assessment is for capacity of 40,000 bbl/d and an amendment for 90,000 bbl/d capacity has not been submitted.

There is no infrastructure in place to support the Corner Project although some of the nearby Leismer plant infrastructure could be used, which includes the access road to the CPF, the diluent import pipeline, capacity in the dilbit sales pipeline to Cheecham, and tank capacity at Cheecham.

Based on Athabasca's development plan, the total Best Estimate capital cost of first commercial production in 2034 for the Corner Project 2 is estimated at approximately $2,137 million (uninflated, unrisked, undiscounted) which includes delineation, SAGD well pairs and central processing facilities.

The contingencies identified for the development of the Corner Contingent Resources are:

- Regulatory Approval – filing an amendment to the existing Corner application.
- Market Conditions – Corner Project 2 is not expected to be sanctioned by the Board until market conditions improve and project funding is secured.
- Delineation – further delineation is required before a final investment decision can be made.
- Firm development plans and detailed cost estimates - have not yet been developed.

- Project Timing – Corner Project 2 is not anticipated to start up until 2034 and significant spending is not anticipated before 2031.

In accordance with the COGE Handbook, Corner risked Best Estimate Contingent Resources have been classified as Development Pending by McDaniel. These Contingent Resources are considered to be Development Pending as they are within a 10 mile radius of the CPF that will be constructed for the Corner Reserves and as there is sufficient delineation to prepare the development strategy consistent with a project evaluation scenario status of development. Athabasca is actively working on this property and intends to develop it in the near term, subject to project sanctioning. The Hangingstone Project took 4.5 years from commencement of preparation of the regulatory application to first steam. Athabasca will execute Corner Project 2 with the same proven execution strategy and facility design and consequently does not need to do further work on Corner Project 2 until 2031 to maintain a reasonable expectation of reaching first steam in 2034. The level of economic analysis is sufficient to assess the development options and overall project viability but is insufficient for a final investment decision. The chance of development of these Contingent Resources is estimated to be 80%.

The positive factors relevant to the Contingent Resource estimates for the Corner Project include:

- The Contingent Resources are located within a 10 mile radius of a CPF that will be constructed for Corner Project 1.
- Using established technology which is being successfully implemented in the nearby Leismer Project.
- A pre-development plan is in place.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the project maturity sub-class of Development Pending.

The negative factors relevant to the Contingent Resource estimates for the Corner Project include:

- Economic sensitivity to future oil pricing.
- Existing infrastructure requires debottlenecking.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- The Corner regulatory application has not yet been amended for Corner Project 2.

See also "*Risk Factors*" in this Annual Information Form.

Description of Hangingstone Contingent Resources

The Contingent Resources assigned to Athabasca's Hangingstone assets assume that such resources will be produced using SAGD technology which has been successfully implemented at the Hangingstone Project since 2015. The infrastructure already in place includes the access road to the CPF, the diluent import pipeline, capacity on the dilbit sales pipeline to Cheecham, tank capacity at Cheecham and the gas import pipeline.

Based on Athabasca's development plan, the total Best Estimate capital cost of first commercial production in 2062 is estimated at approximately $25 million (uninflated, unrisked, undiscounted) which includes delineation and SAGD well pairs the central processing facilities does not need to be expanded beyond the current capacity.

The contingencies identified for the development of the Hangingstone Contingent Resources are:

- Market Conditions – the development is not expected to be sanctioned by the Board until market conditions improve and project funding is secured.

- Delineation – further delineation is required before a final investment decision can be made.

- Firm development plans and detailed cost estimates - have not yet been developed.

- Project Timing – first steam is not expected until 2062 and significant spending is not anticipated before 2061.

In accordance with the COGE Handbook, Hangingstone risked Best Estimate Contingent Resources have been classified as Development. The level of economic analysis is sufficient to assess the development options and overall project viability but is insufficient for a final investment decision. The chance of development of these Contingent Resources is estimated to be 70%.

The positive factors relevant to the Contingent Resource estimates for the Hangingstone include:

- They are within a 10 mile radius of the existing CPF and significant infrastructure is already in place.
- Using established technology which is being successfully implemented at the Hangingstone Project.

The negative factors relevant to the Contingent Resource estimates for the Leismer Project include:

- Economic sensitivity to future oil pricing.
- Ability to access project funding.

See also "*Risk Factors*" in this Annual Information Form.

Description of Dover West Sands Contingent Resources

The estimates of Contingent Resources assigned to Athabasca's Dover West Sands assets assume that the resources will be produced using SAGD technology which has been successfully implemented at the Hangingstone Project since 2015. There are adequate analogues in the area and reservoir studies to confirm that SAGD is applicable to the Dover West Sands reservoir.

The development plan used for the Best Estimate Contingent resource evaluation has three planned phases. Project 1 has a planned production capacity of 20,000 bbl/d, Project 2 increases the total production capacity to 50,000 bbl/d, and Project 3 increases the total production capacity up to 90,000 bbl/d.

The contingencies identified for the development of the Dover West Contingent Resources are:

- Economic viability of the development project
- Firm development plans and detailed cost estimates- have not yet been developed.
- Delineation – further delineation is required before a final investment decision can be made.
- Regulatory Approval – an application for development needs to be filed.
- Market Conditions – Dover West Sand Project is not expected to be sanctioned by the Board until market conditions improve and project funding is secured.
- Project Timing – Dover West Sands Project is not anticipated to start up until 2036 and significant spending is not anticipated before 2033.

In accordance with the COGE Handbook, the discovered recoverable volumes associated with the Dover West sands have been classified as sub-economic contingent resources with a project maturity sub-classification of Development Not Viable.

See also "*Risk Factors*" in this Annual Information Form.

Abandonment and Reclamation Costs

The Independent Report included an estimate of the costs to abandon and reclaim all existing and future wells (not including pipelines and major dedicated facilities) associated with assessed Contingent Resources. No estimate of salvage value is netted against the estimated abandonment and reclamation costs. The estimate for abandonment and reclamation costs are based in part on the Company's estimation of costs to remediate, reclaim and abandon wells in which it has a working interest.

The future net revenues disclosed in this Annual Information Form are based on the Independent Report and contain an allowance for abandonment and reclamation costs for future development wells for Contingent Resources associated with the Leismer, Corner and Hangingstone assets, however such amounts do not include an allowance for facilities or pipelines associated with such assets. The Independent Report includes an aggregate Best Estimate for abandonment and reclamation costs (escalated, unrisked, undiscounted) of $356 million at Leismer and $477 million at Corner, and $108 million at Hangingstone.

APPENDIX B

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

Management of Athabasca Oil Corporation (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes, if disclosed in the statement required by item 1 of section 2.1 of NI 51-101, other information such as contingent resources data. An independent qualified reserves evaluator has evaluated the Company's reserves data and contingent resources data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data and contingent resources data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data; and

(c) the content and filing of this report.

Because the reserves data and contingent resources data is based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) **"Robert Broen"**
Robert Broen
President & Chief Executive Officer

(signed) **"Karla Ingoldsby"**
Karla Ingoldsby
Vice President, Thermal Oil

(signed) **"Ronald J. Eckhardt"**
Ronald J. Eckhardt
Director

(signed) **"Marty Proctor"**
Marty Proctor
Director

Dated March 5, 2025

APPENDIX C

FORM 51-101F2

REPORT ON RESERVES AND CONTINGENT RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Athabasca Oil Corporation
1200, 215 – 9th Avenue SW
Calgary, Alberta T2P 1K3

Attention: The Board of Directors of Athabasca Oil Corporation (the "**Company**")

Re: **Form 51-101F2**
Report on Reserves and Contingent Resources Data
by Independent Qualified Reserves Evaluator or Auditor
of the Company

To the Board of Directors of the Company:

1. We have evaluated the Company's reserves and contingent resources data as at December 31, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024 estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of economic and sub-economic contingent resources and related risked net present value of future net revenue as at December 31, 2024, estimated using forecast prices and costs. For contingent resources with a classification of Development Not Viable, un-risked estimates of volume of contingent resources are presented.

2. The reserves and contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves and contingent resources data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves and contingent resources data are free of material misstatement. An evaluation also includes assessing whether the reserves and contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2024, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

				Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
	Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
Total Company Including Non-Controlling Interest	McDaniel	December 31, 2024	Canada	-	**6,438,453**	-	**6,438,453**
Shareholders of the Parent Company	McDaniel	December 31, 2024	Canada		**6,254,210**		**6,254,210**
Non-Controlling Interest	McDaniel	December 31, 2024	Canada		**184,243**		**184,243**

6. The following tables set forth the risked volume and risked net present value of future net revenue of economic and sub-economic contingent resources (before deduction of income taxes) estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's Board of Directors.

Economic Contingent

					Risked Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)		
Classification	**Independent Qualified Reserves Evaluator**	**Effective Date of Evaluation Report**	**Location of Resources Other than Reserves**	**Risked Volume (Mbbl)**	**Audited**	**Evaluated**	**Total**
Development Pending Contingent Resources (2C)	McDaniel	December 31, 2024	Canada	**836,956** Leismer and Corner	-	1,754,662	1,754,662
Development On Hold Contingent Resources (2C)	McDaniel	December 31, 2024	Canada	**24,935** Hangingstone	-	**7,365**	**7,365**

Sub-Economic Contingent

Classification	**Independent Qualified Reserves Evaluator**	**Effective Date of Evaluation Report**	**Location of Resources Other than Reserves**	**Risked Volume (Mbbl)**
Development Not Viable Contingent Resources (2C)	McDaniel	December 31, 2024	Canada	557,679 Dover West and Hangingstone

7. In our opinion, the reserves and contingent resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves and contingent resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our report referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our report.

9. Because the reserves and contingent resources data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(signed) **"Jared Wynveen"**

____

Jared Wynveen, P. Eng.
Executive Vice President

Calgary, Alberta, Canada
March 5, 2025

APPENDIX D

AUDIT COMMITTEE MANDATE

The Audit Committee (**Committee**) of the board of directors (**Board**) of Athabasca Oil Corporation (**Company**) has the oversight responsibility and specific duties described below and shall comply with the requirements of applicable laws.

COMPOSITION

The Committee will be comprised of at least three directors or such greater number as the Board may determine from time to time. Except to the extent that the Board determines that an exemption contained in National Instrument 52-110 issued by the Canadian Securities Administrators or its successor instrument (**NI 52-110**) is available and determines to rely thereon, all Committee members will be independent within the meaning of NI 52-110.

All Committee members will be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon.

Committee members will be appointed and removed by the Board. The Committee Chair will be appointed by the Board.

RESPONSIBILITIES

The Committee's primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to: (i) the integrity of annual and quarterly financial statements to be provided to the Company's shareholders and regulatory bodies; (ii) compliance with accounting and finance based legal and regulatory requirements; (iii) the external auditor's qualifications, independence and compensation, and communicating with the external auditor; (iv) the system of internal accounting and financial reporting controls that management has established; (v) performance of the external audit process and of the external auditor; (vi) financial policies; (vii) financial and cyber risk management practices; and (viii) transactions or circumstances which could materially affect the financial profile of the Company.

Management of the Company is responsible for preparing the quarterly and annual financial statements of the Company and for maintaining a system of risk assessment and internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, recorded and reported properly. The Committee is responsible for reviewing management's actions and has the authority to investigate any activity of the Company.

SPECIFIC DUTIES

The Committee will:

Audit Leadership

1. Have a clear understanding with the external auditor that it must maintain an open and transparent relationship with the Committee, and that the ultimate accountability of the external auditor is to the Committee, as representatives of the shareholders of the Company.

2. Provide an avenue for communication between each of the external auditor, financial and senior management and the Board. The Committee has the authority to communicate directly with the external auditors and financial and senior management.

Auditor Qualifications and Selection

3. Subject to required shareholder approval of the appointment of auditors of the Company, be solely responsible for recommending to the Board: (i) the external auditor for the purpose of preparing or issuing an auditor's report or performing other audit review or attest services for the Company; and (ii) the compensation of the external auditor. The Committee is directly responsible for overseeing the work of the external auditor, including the resolution of disagreements between management and the external auditor regarding financial reporting and reviewing, considering and making a recommendation to the Board regarding a proposed discharge of the external auditor when circumstances warrant. In all circumstances the external auditor reports directly to the Committee. The Committee is entitled to adequate funding to compensate the external auditor for completing an audit and audit report or performing other audit, review or attest services.

4. Evaluate the external auditor's qualifications, performance and independence. Take all reasonable steps to ensure that the external auditor does not provide non-audit services that would disqualify it as independent under applicable law.

5. Review the experience and qualifications of the senior members of the external audit team and the quality control procedures of the external auditor. Ensure that the lead audit partner of the external auditor is replaced periodically, according to applicable law. Take all reasonable steps to ensure continuing independence of the external audit firm. Present the Committee's conclusions on auditor independence to the Board.

6. Review and approve policies for the Company's hiring of senior employees and former employees of the external auditor who were engaged on the Company's account and make recommendations to the Board for consideration.

Process

7. Pre-approve all audit services (which may include consent and comfort letters in connection with securities offerings). Pre-approve and disclose, as required, the retention of the external auditor for non-audit services to be provided to the Company or any of its subsidiaries permitted under applicable law. In the discretion of the Committee, annually delegate to one or more of its independent members the authority to grant pre-approvals. Approve all audit fees and terms and all non-audit fees.

8. Meet with the external auditor prior to the audit to review the scope and general extent of the external auditor's annual audit including: (i) the planning and staffing of the audit; and (ii) an explanation from the external auditor of the factors considered in determining the audit scope, including the major risk factors.

9. Require the external auditor to provide a timely report setting out: (i) all critical accounting policies, significant accounting judgments and practices to be used; (ii) all alternative treatments of financial information within International Financial Reporting Standards (**IFRS**) that have been discussed with management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the external auditor; and (iii) other material written communications between the external auditor and management.

10. Take all reasonable steps to ensure that officers and directors or persons acting under their direction are aware that they are prohibited from coercing, manipulating, misleading or fraudulently influencing the external auditor when the person knew or should have known that the action could result in rendering the financial statements materially misleading.

11. Upon completion of the annual audit, review the following with management and the external auditor:

(a) The annual financial statements, including related notes and the Management's Discussion and Analysis of Financial Condition and Results of Operations (**MD&A**) of the Company for filing with applicable securities regulators and provision to shareholders, as required.

(b) The significant estimates and judgements and reporting principles, practices and procedures applied by the Company in preparing its financial statements, including any newly adopted accounting policies and the reasons for their adoption.

(c) The results of the audit of the financial statements and whether any limitations were placed on the scope or nature of the audit procedures.

(d) Significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit, including any problems or disagreements with management which, if not satisfactorily resolved, would have caused the external auditor to issue a non-standard report on the financial statements of the Company.

(e) The cooperation received by the external auditor during its audit, including access to all requested records, data and information.

(f) Any other matters not described above that are required to be communicated by the independent auditor to the Committee.

Financial Statements and Disclosure

12. At least quarterly, as part of the review of the annual and quarterly financial statements, receive an oral report from the Company's counsel concerning legal and regulatory matters that may have a material impact on the financial statements.

13. Based on discussions with management and the external auditor, in the Committee's discretion, recommend to the Board whether the annual financial statements and MD&A of the Company should be approved for filing with applicable securities regulators and provision to the Company's shareholders, as required, prior to their disclosure.

14. Review the general types of financial information that it is appropriate for the Company to disclose to external public stakeholders.

15. Review with management and the external auditor the quarterly financial statements and MD&A prior to their release and recommend to the Board for consideration the quarterly results, financial statements, and MD&A prior to filing them with or furnishing them to the applicable securities regulators and prior to any public announcement of financial results for the periods covered, including a written report of the results of the external auditor's reviews of the quarterly financial statements, significant adjustments, new accounting policies, any disagreements between the external auditor and management and the impact on the financial statements of significant events, transactions or changes in accounting principles or estimates that potentially affect the quality of financial reporting.

Internal Control Supervision

16. As required by applicable law, review with management and the external auditor the Company's internal controls over financial reporting, any significant deficiencies or material weaknesses in their design or operation, any proposed major changes to them and any fraud involving management or other employees who have a significant role in the Company's internal controls over financial reporting.

17. Review with management, the Chief Financial Officer and the external auditor the methods used to establish and monitor the Company's policies with respect to unethical or illegal activities by employees that may have a material impact on the financial statements.

18. Meet with management and the external auditor to discuss any relevant significant recommendations that the external auditor may have, particularly those characterized as "material" or "serious". Review responses of management to any significant recommendations from the external auditor and receive follow-up reports on action taken concerning the recommendations.

19. Review with management and the external auditor any correspondence with regulators or government agencies and any employee complaints or published reports which raise material issues regarding the Company's financial statements or accounting policies of the Company (as required).

20. Review with management and the external auditor any off-balance sheet financing mechanisms, transactions or obligations of the Company.

21. Review with management and the external auditor any material related party transactions.

22. Review with the external auditor the quality of the Company's accounting personnel. This review may occur without the presence of management. Review with management the responsiveness of the external auditor to the needs of the Company.

Disclosure Controls and Procedures

23. Periodically assess and be satisfied with the adequacy of procedures in place for the review of public disclosure of financial information extracted or derived from the applicable financial statements (other than the annual and quarterly required filings) for the Company.

Financial Management

24. Regularly review current and expected future compliance with covenants under all financing agreements.

25. Annually review the instruments the Company and its subsidiaries are permitted to use for short-term investments of excess cash and, in the Committee's discretion, make recommendations to the Board for consideration.

26. Review the Company's compliance with required tax remittances and other deductions required by applicable law.

Financial Risk Management

27. Receive reports from management with respect to risk assessment, risk management and major financial risk exposures.

28. Discuss with management guidelines and policies with respect to financial risk assessment and financial risk management, including the processes management uses to assess and manage the Company's financial risk.

29. Annually review the insurance program including coverage for property damage, business interruption, liabilities, and directors and officers.

30. Review any other significant financial exposures of the Company to the risk of a material financial loss including tax audits or other activities.

31. Report to the Board on the financial risks of the Company and make recommendations to the Board for consideration.

32. Establish procedures (through approval of the relevant sections of the Code of Business Conduct) for: (i) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting and financial reporting controls, or auditing matters; and (ii) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters.

33. Once or more annually, as the Committee decides, review and assess the Company's Code of Business Conduct and, in the Committee's discretion, recommend any changes to the Board for consideration.

Cybersecurity

34. Monitor and review risks that pertain to the Company's information technology infrastructure and strategy, cybersecurity controls and risk exposures. The Committee shall discuss with management the actions that management has undertaken to mitigate, monitor and control such exposures.

Committee Reporting

35. Following each meeting of the Committee, report to the Board on the activities, findings and any recommendations of the Committee.

36. Report regularly to the Board and review with the Board any issues that arise with respect to the quality or integrity of the financial statements of the Company, compliance with applicable law and the performance and independence of the external auditor of the Company.

37. Annually review and approve the information regarding the Committee required to be disclosed in the Company's Annual Information Form and Committee's report for inclusion in the annual Proxy Circular.

38. Prepare any reports required to be prepared by the Committee under applicable law.

Committee Meetings

39. Meet at least four times annually and as many additional times as needed to carry out its duties effectively. The Committee may, on occasion and in appropriate circumstances, hold meetings virtually.

40. Meet in separate, non-management, closed sessions with the external auditor at each regularly scheduled meeting.

41. Meet in separate, non-management, in camera sessions at each regularly scheduled meeting.

42. Meet in separate, non-management, closed sessions with any other internal personnel or outside advisors, as needed or appropriate.

43. A quorum for meetings of the Committee will be a majority of its members and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board.

Committee Governance

44. Once or more annually, as the Compensation and Governance Committee (**CG Committee**) decides, receive for consideration that Committee's evaluation of this Mandate and any recommended changes. Review and assess the CG Committee's recommended changes and make recommendations to the Board for consideration.

Advisors/Resources

45. Have the sole authority to retain, oversee, compensate and terminate independent advisors to assist the Committee in its activities.

46. Receive adequate funding from the Company for independent advisors and ordinary administrative expenses that are needed or appropriate for the Committee to carry out its duties.

Other

47. With the CG Committee, the Board and the Board Chair, respond to potential conflict of interest situations, as required.

48. Carry out any other appropriate duties and responsibilities assigned by the Board.

49. To honour the spirit and intent of applicable law as it evolves, authority to make minor technical amendments to this Mandate is delegated to the Secretary, who will report any amendments to the CG Committee at its next meeting.

STANDARDS OF LIABILITY

Nothing contained in this Mandate is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this Mandate are meant to serve as guidelines rather than inflexible rules and, subject to applicable law and the articles and bylaws of the Company, the Committee may adopt such additional procedures and standards, as it deems necessary from time to time to fulfill its responsibilities.

Approved: December 11, 2009

Revised: March 14, 2012
May 11, 2015
July 26, 2017
March 2, 2022
March 5, 2025