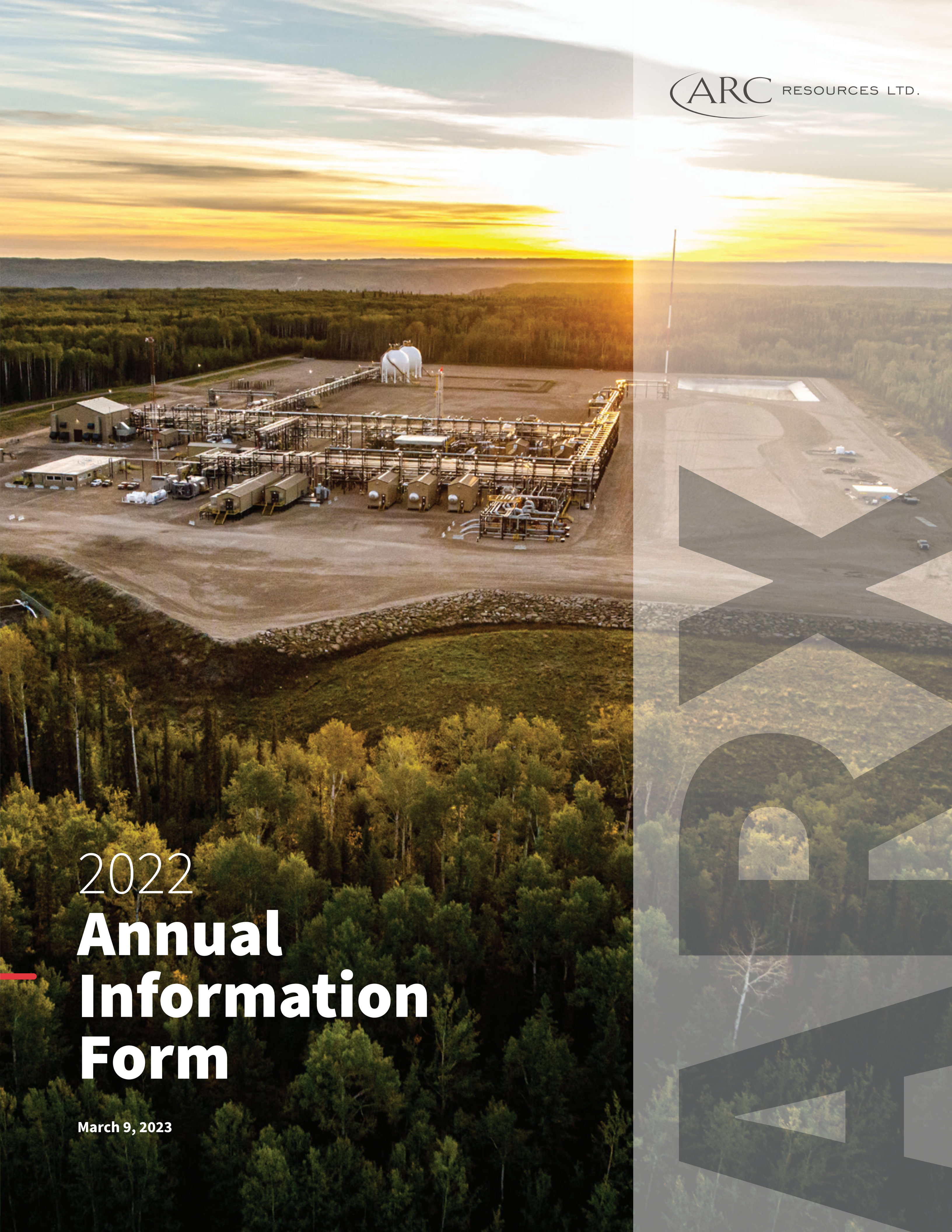


ARC RESOURCES LTD.

# 2022 Annual Information Form

**March 9, 2023**

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# GLOSSARY OF TERMS

In this Annual Information Form, capitalized terms shall have the meanings set forth below:

**ARC Resources, ARC, We, Us, Our, Company, Corporation** means ARC Resources Ltd., a corporation formed by amalgamation under the *Business Corporations Act* (Alberta), and all its controlled entities as a consolidated body at the applicable time;

**Business Combination** means the business combination of ARC Resources Ltd. and Seven Generations Energy Ltd. that closed on April 6, 2021, whereby ARC acquired all the outstanding common shares of Seven Generations Energy Ltd.

**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;

**GLJ** means GLJ Ltd., independent qualified reserves evaluator of Calgary, Alberta;

**GLJ Report** means the report prepared by GLJ and dated February 8, 2023, evaluating the crude oil, natural gas, and natural gas liquids reserves attributed to ARC's properties as at December 31, 2022;

**Montney** means our land bases across the Montney fairway in northeast British Columbia comprised of the Greater Dawson, Sunrise, Sundown, Septimus, Attachie, and Red Creek areas and in northern Alberta in the Kakwa, Ante Creek, and Pouce Coupe areas;

**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*;

**Seven Generations** means Seven Generations Energy Ltd.;

**Shareholders** means holders of common shares of ARC Resources;

**Tax Act** means the *Income Tax Act* (Canada); and

**TSX** means the Toronto Stock Exchange.

Certain other terms used in this Annual Information Form but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

# SPECIAL NOTES TO READER

## Regarding Forward-looking Information

Certain information and statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking information under Canadian securities laws. This information relates to future events or our expected future performance. All information other than statements or information of historical fact may be forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as “seek,” “anticipate,” “budget,” “plan,” “continue,” “estimate,” “expect,” “forecast,” “may,” “will,” “project,” “predict,” “potential,” “target,” “intend,” “could,” “might,” “should,” “believe,” and similar expressions. In addition, there is forward-looking information in this Annual Information Form under the headings: “*Statement of Reserves Data and Other Oil and Gas Information*” as to our reserves and future net revenues from our reserves, pricing and inflation rates, and future development costs; as to the development of our proved undeveloped reserves and probable undeveloped reserves; and as to our future development activities, forward contracts and transportation commitments, reclamation and abandonment obligations, tax horizon, exploration and development activities, and production estimates. This information involves known and unknown risks, uncertainties, and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. We believe the expectations reflected in this forward-looking information are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking information included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. This information speaks only to estimates as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In addition to the forward-looking information identified above, this Annual Information Form, and the documents incorporated by reference, contain forward-looking information pertaining to the performance characteristics of our crude oil and natural gas assets; crude oil and natural gas production levels; the size of the crude oil and natural gas reserves; projections of market prices and costs; expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; treatment under governmental regulatory regimes and tax laws; impacts of current commodity prices on the Corporation, including with respect to abandonment and reclamation obligations; budget expectations; expectations with respect to making customary payments to credit rating organizations; expectations with respect to certain legal proceedings; expectations that ARC's dividends will be classified as "eligible dividends" under the *Tax Act*; and capital expenditure programs.

**Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. In addition, these risks and uncertainties are material factors affecting the success of our business.** Such factors include, but are not limited to: declines in crude oil and natural gas prices; various pipeline constraints; the payment of dividends, if any; variations in interest rates and foreign exchange rates; stock market volatility; uncertainties relating to market valuations; refinancing risk for existing debt and debt service costs; access to external sources of capital; risks associated with our risk management activities; third-party credit risk; risks associated with the exploitation of our assets and our ability to acquire reserves; government regulation, policy and control and changes in governmental legislation; changes in income tax laws, royalty rates, and other incentive programs; uncertainties associated with estimating crude oil and natural gas reserves; risks associated with acquiring, developing, and exploring for crude oil and natural gas and other aspects of our operations; our reliance on hydraulic fracturing; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in climate change laws and other environmental regulations; competition in the crude oil and natural gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel, and drilling and related equipment; risks of non-cash losses as a result of the application of accounting policies; our operating activities and ability to retain key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; risks for United States (“US”) and other non-resident shareholders; risks described in the section entitled “*Risk Factors*” contained within ARC’s Management Discussion and Analysis dated February 9, 2023 (the “MD&A”), available on ARC’s website at www.arcresources.com and on SEDAR at www.sedar.com; and other factors, many of which are beyond our control.

The actual results could differ materially from those results anticipated in this forward-looking information, which are based on assumptions, including as to the market prices for crude oil and natural gas; the continuation of the present policies of the Board of Directors relating to management of ARC, and the payment of dividends, capital expenditures and other matters; the factors and assumptions under the heading "*Significant Factors or Uncertainties Affecting Reserves Data*"; the continued availability of capital and skilled personnel, acquisitions of reserves and undeveloped lands; anticipated abandonment and reclamation costs; the continuation of the current tax and regulatory regime and other assumptions contained in this Annual Information Form.

Statements relating to “reserves” are deemed to be forward-looking information, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking information contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking information except as required by securities laws or regulations.

ARC's audited consolidated financial statements (the “financial statements”) as at and for the year ended December 31, 2022, and MD&A are available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com. The disclosure under the section entitled "*Non-GAAP and Other Financial Measures*" contained in ARC's MD&A is incorporated by reference into this document. Also refer to the section entitled “*Non-GAAP and Other Financial Measures*” in this Annual Information Form.

## Access to Documents

Any document referred to in this Annual Information Form and described as being available on SEDAR at www.sedar.com (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at IR@arcresources.com or at 1200, 308 - 4th Avenue SW, Calgary, Alberta, T2P 0H7.

## Abbreviations and Conversions

| **Oil and Natural Gas Liquids** | |
|---|---|
| bbl | barrel |
| bbl/d | barrels per day |
| Mbbl | thousand barrels |
| MMbbl | million barrels |
| NGLs | natural gas liquids |
| API | indication of specific gravity of crude oil measured on the American Petroleum Institute (“API”) gravity scale |
| **Natural Gas** | |
| Mcf | thousand cubic feet |
| Mcf/d | thousand cubic feet per day |
| MMcf | million cubic feet |
| MMcf/d | million cubic feet per day |
| Bcf | billion cubic feet |
| Bcfe | billion cubic feet equivalent |
| Tcf | trillion cubic feet |
| MMBtu | million British thermal units |
| GJ | gigajoules |
| LNG | liquefied natural gas |
| **Other** | |
| boe | barrels of oil equivalent |
| boe/d | barrels of oil equivalent per day |
| Mboe | thousand barrels of oil equivalent |
| MMboe | million barrels of oil equivalent |
| $M | thousand dollars |
| $MM | million dollars |

We have adopted the standard of 6 Mcf:1 bbl when converting natural gas to boe. Boe may be misleading, particularly if used in isolation. **A boe conversion ratio of six Mcf per barrel is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of the 6:1 conversion ratio, utilizing the 6:1 conversion ratio may be misleading as an indication of value.**

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units), in accordance with the COGE Handbook.

| To Convert From | To | Multiply By |
|---|---|---:|
| cubic metres | cubic feet | 35.49373 |
| cubic feet | cubic metres | 0.0282 |
| barrels | cubic metres | 0.15898 |
| cubic metres | barrels | 6.2901 |
| feet | metres | 0.3048 |
| metres | feet | 3.28084 |
| acres | hectares | 0.404686 |
| hectares | acres | 2.4710541 |

# ARC RESOURCES LTD.

## General

ARC Resources was formed by amalgamation under the *Business Corporations Act* (Alberta). Prior to January 1, 2011, ARC was one of Canada's largest conventional crude oil and natural gas royalty trusts and was founded in 1996.

ARC is a leading Canadian energy company and the nation’s third-largest producer of natural gas and largest producer of condensate. ARC’s business activities include the exploration, development, and production of crude oil, natural gas, and NGLs in Alberta and British Columbia, Canada. ARC has focused on the acquisition and development of resource-rich properties that provide for both near-term and long-term growth. ARC trades on the TSX under the symbol ARX and currently pays a quarterly dividend to its shareholders.

At December 31, 2022, ARC had 584 permanent professional, technical, and support staff, with 345 employees located in the Calgary office and 239 employees located across ARC’s operating areas.

Our principal office is located at 1200, 308 - 4th Avenue SW, Calgary, Alberta, T2P 0H7 and our registered office is located at 2400, 525 - 8th Avenue SW, Calgary, Alberta, T2P 1G1.

## Organizational Structure

The following diagram illustrates the intercorporate relationship between ARC and its subsidiaries, the percentage of votes attached to all voting securities of the subsidiaries beneficially owned, or controlled or directed, directly or indirectly, by ARC and the jurisdiction of incorporation of the subsidiaries.


## Strategy

ARC’s vision is to be the “Best-in-Class Responsible Energy Producer”, with its long-term strategy founded upon four key pillars: high-quality assets and operational excellence, financial sustainability and return on investment, people and environmental, social, and governance (“ESG”) leadership, and commercial activities and risk management. These pillars have created a strong foundation for excellent business performance and have positioned the Company to prudently manage volatile market conditions. ARC is committed to paying a meaningful dividend and maintaining a strong financial position to provide superior long-term returns for its shareholders. Through its history, the Company has built a commodity-diverse portfolio of world-class, low-cost, and low-emissions assets, and continuously creates value and optimizes revenue through upstream and downstream business development and other commercial activities. A strong culture of respect, integrity, trust, and community supports these activities and commitments. ARC prioritizes the safety of employees, contractors, communities, and the environment.

# Development of our Business

The following is a description of the general development of our business over the last three financial years and to the date of this Annual Information Form.

## 2020

**Annual average production of 161,564 boe per day.** ARC delivered full-year average production of 161,564 boe per day in 2020, representing a 16 per cent increase relative to 2019. The increase in production was driven by new production associated with the Dawson Phase IV facility, which was brought on-stream in the second quarter of 2020. Natural gas production at Sunrise also increased in 2020, with the Sunrise Phase II facility being brought to full facility capacity in the fourth quarter of 2019.

**Total proved plus probable reserves of 929 MMboe identified and 203 per cent of produced reserves replaced.** ARC's total proved plus probable reserves increased two per cent relative to 2019, totalling 929 MMboe at December 31, 2020. During the year, 203 per cent of total proved plus probable reserves were replaced through organic development activities. Total proved reserves were 603 MMboe and proved producing reserves were 268 MMboe at December 31, 2020.

**Executive appointments.** Effective February 6, 2020, Kristen J. Bibby was appointed to the position of Senior Vice President and Chief Financial Officer. Effective February 20, 2020, Terry M. Anderson was appointed to the position of Chief Executive Officer and was later appointed President and Chief Executive Officer on June 24, 2020.

**Dividend reduced to a quarterly payment of $0.06 per share from a monthly payment of $0.05 per share.** Following the rapid decline in commodity prices caused by the COVID-19 pandemic, and to preserve the Company's strong financial position, ARC announced in March 2020 that it would reduce its monthly dividend of $0.05 per share to a quarterly dividend of $0.06 per share.

**Budgeted capital expenditures reduced to preserve balance sheet strength.** Concurrent with the dividend reduction announcement, ARC reduced its capital budget of $500 million to $300 million, deferring a portion of the drilling and completions activities planned in the Greater Dawson and Ante Creek areas. Following an improvement in commodity prices, ARC subsequently increased its 2020 capital budget to $350 million in November 2020.

**Cash flow used in investing activities was $364.3 million and capital expenditures[(1)] totalled $343.2 million.** ARC focused on its core Montney assets in 2020, investing $343.2 million in capital expenditures. A significant focus of ARC's 2020 capital program was to expand the Company's low-cost Montney business by completing the Dawson Phase IV facility in the second quarter of 2020, adding processing capacity of 90 MMcf per day of natural gas and 10,500 barrels per day of condensate and NGLs. ARC drilled 59 wells and completed 66 wells in 2020.

## 2021

**Acquisition and integration of Seven Generations.** On February 10, 2021, ARC announced that it had entered into a Business Combination with Seven Generations in an all-share transaction. The Business Combination was structured through a plan of arrangement under the *Canada Business Corporations Act*, where Seven Generations shareholders received 1.108 common shares of ARC for each class "A" common share of Seven Generations. On April 6, 2021, ARC issued approximately 369.4 million common shares to acquire all of the outstanding Seven Generations class "A" common shares, making Seven Generations a wholly-owned subsidiary of ARC. On May 1, 2021, ARC amalgamated with Seven Generations.

**Issuance of unsecured notes.** On March 10, 2021, ARC completed the issuance of two tranches of senior unsecured notes of $1.0 billion aggregate principal amount with a weighted average interest rate of 2.965 per cent and average term of 7.75 years (the "2021 Notes"). The 2021 Notes were assigned a rating of BBB with a stable trend by DBRS Morningstar upon successful completion of the Business Combination. On April 6, 2021, ARC used the proceeds from the 2021 Notes, combined with draws on its $2.0 billion unsecured extendible revolving credit facility (the "Credit Facility"), to repay all of Seven Generations' outstanding senior notes. ARC subsequently amended and restated the Credit Facility in October 2021, extending the tenor from three to four years and executing amendments to align with credit facilities of other investment-grade energy companies. Additionally, ARC repaid the entire principal amount outstanding of its legacy private senior notes in September 2021.

(1) Non-GAAP financial measure that is not a standardized financial measure under International Financial Reporting Standards ("IFRS") and may not be comparable to similar financial measures disclosed by other issuers. The most directly comparable GAAP measure for capital expenditures is cash flow used in investing activities. Certain additional disclosures for this non-GAAP measure have been incorporated by reference and can be found in the section entitled *"Non-GAAP and Other Financial Measures"* in ARC's MD&A available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

**Annual average production of 302,003 boe per day.** ARC delivered record full-year average production of 302,003 boe per day in 2021. Production increased 87 per cent relative to 2020, reflecting nine months of contribution from the Kakwa asset acquired through the Business Combination.

**Cash flow used in investing activities was $808.1 million and capital expenditures totalled $1.1 billion.** ARC's 2021 capital program demonstrated capital discipline and prioritized efficiently integrating the Kakwa asset into its portfolio. During the year, ARC completed two small infrastructure optimization and expansion projects at Sunrise and Parkland and drilled 141 wells and completed 132 wells.

**Total proved plus probable reserves of 1,761 MMboe identified.** The acquisition of the Kakwa asset approximately doubled ARC's reserves volumes, while development additions replaced greater than 100 per cent of production in all reserves categories, reflecting ARC's successful operational execution throughout 2021. Total proved plus probable reserves were 1,761 MMboe, total proved reserves were 1,185 MMboe, and proved producing reserves were 503 MMboe as at December 31, 2021.

**Returns to shareholders accelerated.** Reflecting increased profitability and ARC's ability to capture $190 million in annual savings due to synergies of the Business Combination, ARC increased its quarterly dividend twice during 2021. ARC increased its third quarter dividend by 10 per cent, from $0.06 per share to $0.066 per share, and subsequently increased its fourth quarter dividend by 52 per cent, from $0.066 per share to $0.10 per share.

**Normal course issuer bid ("NCIB") initiated.** ARC received TSX approval to commence an NCIB, which allowed ARC to purchase up to 72.2 million of its outstanding common shares, representing 10 per cent of the Company's public float over a 12-month period commencing September 1, 2021. From September 1, 2021 to December 31, 2021, ARC repurchased 30.9 million or approximately four per cent of its common shares outstanding at a weighted average price of $11.17 for total consideration of $345.2 million.

**Long-term natural gas supply agreement secured.** ARC advanced its marketing strategy by entering into its first long-term supply agreement to supply approximately 150 MMcf per day of natural gas from ARC's Sunrise facilities to an LNG Canada participant. The agreement will commence with the start-up of LNG Canada.

**Executive appointments.** Upon close of the Business Combination, Armin Jahangiri was appointed to the position of Senior Vice President, Capital Operations; Larissa M. Conrad was appointed to the position of Senior Vice President, Development; Lisa A. Olsen was appointed to the position of Vice President, People and Corporate; Kristin L. Cerny was appointed to the position of Vice President, Finance; Brian R. Groundwater was appointed to the position of Vice President, Engineering; Lynne P. Chrumka was appointed to the position of Vice President, Geosciences; Brian J. Newmarch was appointed to the position of Vice President, Sustainability; and David B. Holt was appointed to the position of Senior Vice President and Chief Operating Officer. Effective September 8, 2021, Sean W. Stuart was appointed to the position of Vice President, Capital Operations.

## 2022

**Record annual average production of 345,613 boe per day.** ARC delivered record full-year average production of 345,613 boe per day in 2022, representing a 14 per cent increase relative to 2021. The increase in production was driven by increased condensate and NGLs production from Kakwa, and recognizing a full year of production from this asset which was acquired in the Business Combination.

**Cheniere long-term natural gas supply agreement.** In the second quarter of 2022, ARC entered into a long-term natural gas supply agreement with Cheniere Energy, Inc. ("Cheniere"). The agreement commences with the commercial operation of Train 7 of the Corpus Christi Stage III expansion which is expected in 2027. ARC will deliver natural gas to Cheniere through existing pipeline capacity and will receive an LNG price based on Platts JKM™ (Japan Korea Marker), after deductions for fixed LNG shipping costs and a fixed liquefaction fee.

**Cash flow used in investing activities was $1.4 billion and capital expenditures totaled $1.4 billion.** ARC executed its 2022 capital program safely and efficiently. In 2022, in addition to drilling 134 wells and completing 126 wells, ARC invested in infrastructure with the expansion of its Sunrise facility and the electrification of its Dawson Phase III and IV facilities, which are expected to be completed in 2023.

(2) This supplementary financial measure is comprised of the before-tax net present value for proved plus probable reserves, discounted at 10 per cent, as determined in accordance with NI 51-101, divided by diluted weighted average common shares.

**Net present value of proved plus probable reserves increased 49 per cent.** ARC's before-tax net present value of proved plus probable reserves, discounted at 10 per cent, increased 49 per cent to $34.00 per share[(2)] or $21.1 billion at December 31, 2022. The increase was driven by positive technical revisions and extensions and improved recovery, particularly at Kakwa, along with stronger commodity prices and fewer shares outstanding.

**Reserves per share grew between 14 and 22 per cent in all categories.** ARC's proved producing reserves increased 22 per cent per share to 549 MMboe, primarily due to strong results at Kakwa where proved producing reserves grew by 17 per cent. Positive technical revisions accounted for a nine per cent increase in proved producing reserves, with the largest increase at Kakwa being an 11 per cent increase in proved producing reserves.

**Dividend increase of 50 per cent over the course of the year.** ARC increased its quarterly dividend twice during 2022. During the first quarter, ARC increased its dividend by 20 per cent, from $0.10 per share to $0.12 per share. Subsequently, in the fourth quarter, ARC announced an additional increase of 25 per cent to $0.15 per share.

**NCIB renewed.** On August 30, 2022, ARC received TSX approval to renew its NCIB, which allows ARC to purchase 65.3 million of its outstanding common shares, representing 10 per cent of the Company's public float over a 12-month period commencing September 1, 2022. During the year ended December 31, 2022, ARC repurchased 74.6 million common shares at a weighted average price of $17.36 for a total cost of $1.3 billion.

**Equitable Origin's EO100™ Certification.** In April 2022, ARC received certification under Equitable Origin's EO100™ Standard for Responsible Development for its northeast BC assets, including Greater Dawson and Sunrise. In January 2023, the Company achieved certification of its Ante Creek asset, with 100 per cent of the Company's production base now certified under this global standard.

**Executive appointments.** Effective January 10, 2022, Armin Jahangiri was appointed to the position of Senior Vice President and Chief Operating Officer; Larissa M. Conrad was appointed to the position of Senior Vice President and Chief Development Officer; Ryan V. Berrett was appointed to the position of Senior Vice President, Marketing; Lisa A. Olsen was appointed to the position of Senior Vice President, People and Corporate; and Katherine J. Gomes was appointed to the position of Vice President, Controller. Effective March 10, 2022, Brian R. Groundwater was appointed to the position of Vice President, Engineering and Geoscience. Effective September 16, 2022, Tejay D. Haugen was appointed to the position of Vice President, Operations Planning; and Sean R. A. Calder was appointed to the position of Vice President, Field Operations.

# STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information is set forth below (the "Statement"). The effective date of the Statement is December 31, 2022. The Statement conforms to the requirements of NI 51-101.

The reserves data set forth below is based upon an evaluation by GLJ and contained in the GLJ Report dated February 8, 2023. The reserves data summarizes our reserves and the net present values of future net revenues for these reserves, using forecast prices and costs prior to provision for interest, general and administrative expenses, and the impact of any financial risk management activities. Reserves evaluation includes abandonment and reclamation costs for all assets with attributed reserves as well as future drilling locations attributed proved and/or probable reserves. Future net revenues have been presented on a before-tax and after-tax basis. We engaged GLJ to provide an evaluation of proved and proved plus probable reserves.

**It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained, and variances could be material. The recovery and reserves estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" in conjunction with the following tables and notes. For more information as to the risks involved, see the section entitled "*Risk Factors*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.**

The Report on Reserves Data by GLJ on Form 51-101F2 and the Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 are attached as Appendices A and B to this Annual Information Form.

# Disclosure of Reserves Data

***Summary of 2022 Crude Oil and Natural Gas Reserves - Based on Forecast Prices and Costs***

| Company Gross Reserves | Light Crude Oil and Medium Crude Oil (Mbbl) | Heavy Crude Oil (Mbbl) | Tight Oil (Mbbl) | NGLs (Mbbl)(1)(2) | Total Crude Oil and NGLs (Mbbl) | Conven-tional Natural Gas (MMcf) | Shale Gas (MMcf) | Total Gas (MMcf) | Total Oil Equivalent (Mboe) |
|---|---|---|---|---|---|---|---|---|---|
| **PROVED** | | | | | | | | | |
| Developed Producing | 0 | 479 | 9,713 | 181,423 | 191,615 | 44,526 | 2,097,738 | 2,142,265 | 548,659 |
| Developed Non-producing | — | — | 3,085 | 37,982 | 41,068 | 4,420 | 327,311 | 331,730 | 96,356 |
| Undeveloped | — | — | 5,420 | 171,933 | 177,354 | — | 2,320,584 | 2,320,584 | 564,118 |
| **TOTAL PROVED** | **0** | **479** | **18,219** | **391,339** | **410,037** | 48,946 | **4,745,633** | **4,794,579** | **1,209,133** |
| PROBABLE | 0 | 166 | 13,167 | 220,608 | 233,941 | 16,268 | 2,296,593 | 2,312,861 | 619,418 |
| **TOTAL PROVED PLUS PROBABLE** | **1** | **645** | **31,386** | **611,947** | **643,978** | **65,214** | **7,042,227** | **7,107,440** | **1,828,551** |

| Company Net Reserves | Light Crude Oil and Medium Crude Oil (Mbbl) | Heavy Crude Oil (Mbbl) | Tight Oil (Mbbl) | NGLs (Mbbl)(1)(2) | Total Crude Oil and NGLs (Mbbl) | Conven-tional Natural Gas (MMcf) | Shale Gas (MMcf) | Total Gas (MMcf) | Total Oil Equivalent (Mboe) |
|---|---|---|---|---|---|---|---|---|---|
| **PROVED** | | | | | | | | | |
| Developed Producing | 0 | 811 | 8,081 | 137,946 | 146,839 | 39,030 | 1,770,873 | 1,809,903 | 448,490 |
| Developed Non-producing | — | — | 2,500 | 30,844 | 33,344 | 3,796 | 288,226 | 292,022 | 82,014 |
| Undeveloped | — | — | 4,230 | 138,954 | 143,184 | — | 1,992,949 | 1,992,949 | 475,342 |
| **TOTAL PROVED** | **0** | **811** | **14,811** | **307,744** | **323,367** | 42,826 | **4,052,047** | **4,094,873** | **1,005,846** |
| PROBABLE | 0 | 268 | 10,095 | 166,570 | 176,934 | 14,115 | 1,932,017 | 1,946,132 | 501,289 |
| **TOTAL PROVED PLUS PROBABLE** | **1** | **1,080** | **24,906** | **474,315** | **500,301** | **56,941** | **5,984,064** | **6,041,005** | **1,507,135** |

1) NGLs includes associated NGLs for both Conventional and Shale/Tight Reservoirs, and includes condensate, propane, and butane.
2) Condensate and Pentanes Plus represent 63 per cent of proved producing NGLs, 66 per cent of total proved NGLs, and 69 per cent of total proved plus probable NGLs.

### *Net Present Value of Future Net Revenues - Based on Forecast Prices and Costs*

| Before-tax Net Present Value [1] ($ millions) | Undiscounted | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
|---|---|---|---|---|---|
| **PROVED** | | | | | |
| Developed Producing | 11,742 | 9,586 | 8,096 | 7,048 | 6,283 |
| Developed Non-producing | 2,627 | 2,104 | 1,766 | 1,532 | 1,359 |
| Undeveloped | 11,193 | 7,137 | 4,798 | 3,346 | 2,388 |
| **TOTAL PROVED** | **25,562** | **18,828** | **14,660** | **11,926** | **10,031** |
| PROBABLE | 17,559 | 10,010 | 6,484 | 4,597 | 3,471 |
| **TOTAL PROVED PLUS PROBABLE** | **43,121** | **28,838** | **21,144** | **16,523** | **13,502** |

| After-tax Net Present Value [1][2][3] ($ millions) | Undiscounted | Discounted at 5% | Discounted at 10% | Discounted at 15% | Discounted at 20% |
|---|---|---|---|---|---|
| **PROVED** | | | | | |
| Developed Producing | 9,863 | 8,130 | 6,903 | 6,032 | 5,392 |
| Developed Non-producing | 1,999 | 1,595 | 1,332 | 1,150 | 1,015 |
| Undeveloped | 8,445 | 5,257 | 3,419 | 2,284 | 1,541 |
| **TOTAL PROVED** | **20,308** | **14,982** | **11,655** | **9,466** | **7,947** |
| PROBABLE | 13,323 | 7,542 | 4,847 | 3,411 | 2,559 |
| **TOTAL PROVED PLUS PROBABLE** | **33,631** | **22,524** | **16,501** | **12,877** | **10,507** |

1) Reflects values inclusive of estimated abandonment and reclamation for all active assets with attributed reserves.
2) Based on ARC's estimated tax pools at year-end 2022.
3) The after-tax net present value of the future net revenue attributed to ARC's crude oil and natural gas assets reflects the tax burden on the assets on a standalone basis and does not necessarily reflect the business entity tax-level situation or tax planning. ARC's financial statements and the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com, should be consulted for information at the business entity level.

### *Total Future Net Revenues (Undiscounted) - Based on Forecast Prices and Costs*

| Reserves Category ($ millions) | Revenue | Royalties | Operating Expense | Development Costs | Abandonment and Reclamation Costs [1] | Future Net Revenue before Income Taxes | Income Taxes | Future Net Revenue after Income Taxes |
|---|---|---|---|---|---|---|---|---|
| Proved Reserves | 54,954 | 10,580 | 11,402 | 6,615 | 794 | 25,562 | 5,254 | 20,308 |
| Proved plus Probable Reserves | 89,062 | 18,126 | 17,784 | 9,067 | 964 | 43,121 | 9,489 | 33,631 |

1) Reflects estimated abandonment and reclamation for all active assets with attributed reserves.

### *Future Net Revenues by Production Group - Based on Forecast Prices and Costs*

| Reserves Category | Production Group | Future Net Revenue before Income Taxes (Discounted at 10% per Year) ($ millions) | Per Unit [1] |
|---|---|---|---|
| Proved Reserves | Light Crude Oil and Medium Crude Oil [2] | — | — |
| | Heavy Crude Oil [2][3] | 29 | $36.15/bbl |
| | Tight Oil [2] | 962 | $64.95/bbl |
| | Conventional Natural Gas [4] | 97 | $2.28/Mcf |
| | Shale Gas [4] | 13,572 | $3.50/Mcf |
| | **Total** | **14,660** | **$14.57/boe** |
| Proved Plus Probable Reserves | Light Crude Oil and Medium Crude Oil [2] | — | — |
| | Heavy Crude Oil [2][3] | 34 | $31.28/bbl |
| | Tight Oil [2] | 1,485 | $59.63/bbl |
| | Conventional Natural Gas [4] | 117 | $2.08/Mcf |
| | Shale Gas [4] | 19,508 | $3.42/Mcf |
| | **Total** | **21,144** | **$14.03/boe** |

1) Unit values are based on Net Reserves.
2) Including solution gas and other by-products.
3) Per unit revenue positively impacted by a portion of value coming from royalty interest reserves.
4) Including by-products but excluding solution gas and other by-products from crude oil wells.

## Forecast Prices and Costs

Forecast prices and costs are prices and costs that are generally acceptable, in the opinion of GLJ, as being a reasonable outlook of the future as of the evaluation effective date. To the extent that there are fixed or presently determinable future prices or costs to which we are 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 have been incorporated into the forecasts.

The forecast cost and price assumptions include increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, natural gas, and NGLs benchmark prices reference GLJ January 1, 2023 price forecasts and exchange rates which reflect current forward commodity prices as at December 31, 2022, in accordance with the COGE Handbook, which states that major benchmark commodity price forecasts, up to and including the second full forecast year, should not deviate from current forward commodity prices by more than 20 per cent.

***Summary of GLJ January 1, 2023 Forecast Prices and Inflation Rate Assumptions***

| | Crude Oil | | | | Natural Gas | | Edmonton Liquids Prices | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Forecast | WTI Cushing Oklahoma (US$/bbl) | Edmonton Par Price 40° API (Cdn$/bbl) | Hardisty Heavy 12° API (Cdn$/bbl) | Cromer Medium 29.3° API (Cdn$/bbl) | NYMEX Henry Hub[1] Gas Price (US$/ MMBtu) | AECO Gas Price (Cdn$/ MMBtu) | Propane (Cdn$/bbl) | Butane (Cdn$/bbl) | Pentanes Plus (Cdn$/bbl) | Inflation Rate[2] (%/Year) | Exchange Rate[3] (US$/ Cdn$) |
| 2023 | 75.00 | 97.96 | 54.54 | 95.51 | 4.71 | 4.36 | 39.18 | 55.84 | 99.32 | — | 0.735 |
| 2024 | 75.00 | 95.30 | 58.19 | 92.92 | 4.50 | 4.77 | 40.50 | 57.18 | 99.33 | 2.0 | 0.745 |
| 2025 | 75.43 | 94.50 | 64.87 | 92.14 | 4.27 | 4.47 | 42.53 | 56.70 | 98.58 | 2.0 | 0.755 |
| 2026 | 76.94 | 95.14 | 71.99 | 92.76 | 4.35 | 4.49 | 42.81 | 57.08 | 101.88 | 2.0 | 0.765 |
| 2027 | 78.48 | 95.79 | 74.71 | 93.39 | 4.44 | 4.53 | 43.10 | 57.47 | 102.58 | 2.0 | 0.775 |
| 2028 | 80.05 | 97.70 | 78.15 | 95.26 | 4.53 | 4.62 | 43.97 | 58.62 | 104.63 | 2.0 | 0.775 |
| 2029 | 81.65 | 99.66 | 79.86 | 97.17 | 4.62 | 4.71 | 44.85 | 59.79 | 106.72 | 2.0 | 0.775 |
| 2030 | 83.28 | 101.65 | 81.47 | 99.10 | 4.71 | 4.80 | 45.74 | 60.99 | 108.85 | 2.0 | 0.775 |
| 2031 | 84.95 | 103.68 | 83.13 | 101.09 | 4.80 | 4.89 | 46.66 | 62.21 | 111.03 | 2.0 | 0.775 |
| 2032 | 86.65 | 104.31 | 85.31 | 101.70 | 4.90 | 4.99 | 46.94 | 62.59 | 113.25 | 2.0 | 0.775 |
| Thereafter | (4) | (4) | (4) | (4) | (4) | (4) | (4) | (4) | (4) | 2.0 | 0.775 |

1) GLJ assigns a value to ARC's existing natural gas physical sales contracts at Dawn, Chicago, Ventura, and Malin consuming markets based upon GLJ's forecasted differential to NYMEX Henry Hub, contracted volumes, and transportation costs. No incremental value is assigned to potential future contracts which were not in place as of December 31, 2022.
2) Inflation rates for forecasting costs.
3) Exchange rates used to generate the benchmark reference prices in this table.
4) Prices escalate two per cent per year from 2033.

ARC's weighted average realized prices for the year ended December 31, 2022, were $8.15 per Mcf for shale gas and conventional natural gas; $116.51 per barrel for tight oil, light crude oil and medium crude oil; $80.84 per barrel for heavy crude oil; $118.17 per barrel for condensate; and $27.98 per barrel for NGLs.

## Definitions and Notes to Reserves Data Tables

In the tables set forth above and elsewhere in this Annual Information Form, the following definitions and other notes are applicable:

1. "**Gross**" means:

   a) in relation to our interest in production and reserves, our interest (operating and non-operating) before deduction of royalties and without including any royalty interest to us;

   b) in relation to wells, the total number of wells in which we have an interest; and

   c) in relation to properties, the total area of properties in which we have an interest.

2. "**Net**" means:

   a) in relation to our interest in production and reserves, our interest (operating and non-operating) after deduction of royalty obligations, plus our royalty interest in production or reserves;

b) in relation to wells, the total number of wells in which we have an interest multiplied by the working interest we owned; and

c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we owned.

3. Columns may not add due to rounding.

4. The forecast price and cost assumptions assumed the continuance of current laws and regulations.

5. All factual data supplied to GLJ was accepted as represented. No field inspection was conducted.

6. The crude oil, natural gas, and NGLs reserves estimates presented in the GLJ Report are based on the definitions and guidelines contained in the CSA Notice 51-324 - *Revised Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* and the COGE Handbook. A summary of those definitions are set forth below.

## Reserves Categories

Reserves are estimated remaining quantities of crude oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on analysis of drilling, geological, geophysical, and engineering data; through the use of established technology; and within specified economic conditions.

Reserves are classified according to the degree of certainty associated with the estimates.

a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories:

a) **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. The developed category may be subdivided into producing and non-producing.

i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

ii) **Developed non-producing reserves** are 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.

b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved and probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities, and completion intervals in the pool and their respective development and production status.

### Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

a) at least a 90 per cent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

b) at least a 50 per cent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

## Reconciliations of Changes in Reserves

The following table sets forth the reconciliation of our gross reserves as at December 31, 2022, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2022 and as at December 31, 2021 include working interest reserves before royalties payable and without including gross royalties receivable. Key highlights include:

- Continued strong well performance across ARC's Montney assets drove positive total proved and proved plus probable technical revisions in the Shale Gas and NGLs categories.
- Kakwa’s proved producing reserves realized positive technical revisions as a result of improved well performance, driven by increasing interwell spacing.
- Development in the Greater Dawson, Sunrise, Ante Creek, and Kakwa areas resulted in positive extensions and improved recovery reserve additions in all categories.
- Economic factors had a minor, positive impact to total reserves. Less than one per cent of total proved and total proved plus probable reserves were added due to improved forecast pricing for both crude oil and natural gas.

## *Reconciliation of Gross Reserves by Principal Product Type*

| | Light Crude Oil and Medium Crude Oil (Mbbl) | Heavy Crude Oil (Mbbl) | Tight Oil (Mbbl) | NGLs (Mbbl)(1)(2)(3) | Total Crude Oil and NGLs (Mbbl) | Conven-tional Natural Gas (MMcf) | Shale Gas (MMcf) | Total Gas (MMcf) | Total Oil Equi-valent (Mboe) |
|---|---|---|---|---|---|---|---|---|---|
| **PROVED PRODUCING** | | | | | | | | | |
| December 31, 2021 | 0 | 487 | 9,962 | 158,983 | 169,433 | 47,933 | 1,952,153 | 2,000,085 | 502,780 |
| Extensions and Improved Recovery (4) | 1 | — | 2,107 | 50,038 | 52,146 | 4,783 | 415,239 | 420,021 | 122,150 |
| Technical Revisions | — | (2) | 167 | 18,173 | 18,338 | (1,800) | 166,979 | 165,179 | 45,868 |
| Acquisitions | — | — | — | — | — | — | — | — | — |
| Dispositions | — | — | — | (184) | (184) | (2,291) | — | (2,291) | (566) |
| Economic Factors | — | — | 292 | 1,081 | 1,373 | 4,185 | 14,403 | 18,588 | 4,471 |
| Production (5) | 0 | (7) | (2,815) | (46,668) | (49,490) | (8,283) | (451,034) | (459,317) | (126,043) |
| **December 31, 2022** | **0** | **479** | **9,713** | **181,423** | **191,615** | **44,526** | **2,097,738** | **2,142,265** | **548,659** |
| **PROVED** | | | | | | | | | |
| December 31, 2021 | 0 | 487 | 18,418 | 391,476 | 410,381 | 50,418 | 4,596,824 | 4,647,242 | 1,184,922 |
| Extensions and Improved Recovery (4) | — | — | 1,827 | 38,374 | 40,201 | — | 417,970 | 417,970 | 109,863 |
| Technical Revisions | 0 | (2) | 215 | 5,020 | 5,233 | 4,602 | 155,049 | 159,650 | 31,842 |
| Acquisitions | — | — | — | — | — | — | — | — | — |
| Dispositions | — | — | — | (184) | (184) | (2,291) | — | (2,291) | (566) |
| Economic Factors | — | — | 575 | 3,320 | 3,895 | 4,501 | 26,824 | 31,325 | 9,116 |
| Production (5) | 0 | (7) | (2,815) | (46,668) | (49,490) | (8,283) | (451,034) | (459,317) | (126,043) |
| **December 31, 2022** | **0** | **479** | **18,219** | **391,339** | **410,037** | **48,946** | **4,745,633** | **4,794,579** | **1,209,133** |
| **PROBABLE** | | | | | | | | | |
| December 31, 2021 | 0 | 166 | 12,181 | 184,888 | 197,235 | 14,701 | 2,256,249 | 2,270,950 | 575,726 |
| Extensions and Improved Recovery (4) | — | — | 982 | 34,062 | 35,043 | — | 155,868 | 155,868 | 61,021 |
| Technical Revisions | 0 | — | 1 | 3,130 | 3,131 | 1,308 | (122,946) | (121,638) | (17,142) |
| Acquisitions | — | — | — | — | — | — | — | — | — |
| Dispositions | — | — | — | (50) | (50) | (861) | — | (861) | (194) |
| Economic Factors | — | — | 4 | (1,422) | (1,418) | 1,120 | 7,422 | 8,543 | 6 |
| **December 31, 2022** | **0** | **166** | **13,167** | **220,608** | **233,941** | **16,268** | **2,296,593** | **2,312,861** | **619,418** |
| **PROVED PLUS PROBABLE** | | | | | | | | | |
| December 31, 2021 | 0 | 653 | 30,598 | 576,364 | 607,616 | 65,118 | 6,853,073 | 6,918,191 | 1,760,648 |
| Extensions and Improved Recovery (4) | — | — | 2,809 | 72,436 | 75,244 | — | 573,838 | 573,838 | 170,884 |
| Technical Revisions | 0 | (2) | 216 | 8,150 | 8,364 | 5,910 | 32,103 | 38,012 | 14,700 |
| Acquisitions | — | — | — | — | — | — | — | — | — |
| Dispositions | — | — | — | (234) | (234) | (3,153) | — | (3,153) | (760) |
| Economic Factors | — | — | 579 | 1,899 | 2,477 | 5,621 | 34,247 | 39,868 | 9,122 |
| Production (5) | 0 | (7) | (2,815) | (46,668) | (49,490) | (8,283) | (451,034) | (459,317) | (126,043) |
| **December 31, 2022** | **1** | **645** | **31,386** | **611,947** | **643,978** | **65,214** | **7,042,227** | **7,107,440** | **1,828,551** |

1) NGLs includes associated NGLs for both Conventional and Shale/Tight Reservoirs.
2) Condensate and Pentanes Plus represent 66 per cent of total proved NGLs, 71 per cent of probable NGLs and 67 per cent of proved plus probable NGLs in the December 31, 2021 opening balance.
3) Condensate and Pentanes Plus represent 66 per cent of total proved NGLs, 73 per cent of probable NGLs and 69 per cent of proved plus probable NGLs in the December 31, 2022 closing balance.
4) Reserve additions for Discoveries, Infill Drilling, Extensions, and Improved Recovery are combined and reported as “Extensions and Improved Recovery”.
5) Production does not include royalty interest volumes and therefore differs from the production shown in the Production History table within this document.

## Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributed to the reserves categories noted below:

***Future Development Costs***

| Year | Proved Reserves ($ millions) | Proved Plus Probable Reserves ($ millions) |
|---|---|---|
| 2023 | 1,686 | 1,722 |
| 2024 | 1,280 | 1,425 |
| 2025 | 1,105 | 1,249 |
| 2026 | 883 | 1,106 |
| 2027 | 830 | 1,184 |
| Remainder | 831 | 2,381 |
| Total: Undiscounted | 6,615 | 9,067 |
| Total: Discounted at 10% per year | 5,187 | 6,690 |

We expect to fund the development costs of the reserves through a combination of sources including funds from operations and debt.

Changes in forecasted future development capital occur annually as a result of development activities, acquisition and disposition activities, and capital cost estimates that reflect the independent qualified reserve evaluator's best estimate of what it will cost to bring the proved plus probable undeveloped reserves on production at that time. Undiscounted future development costs ("FDC") for proved plus probable undeveloped reserves increased $1.7 billion compared to year-end 2021, to total $9.1 billion at year-end 2022. The increase in FDC was primarily driven by inflationary pressures.

Estimates of reserves and future net revenues have been made assuming the development of each property, in respect of which the estimate is made, will occur, without regard to the likely availability to us of funding required for the development. There can be no guarantee that funds will be available or that we will allocate funding to develop all of the reserves attributed in the GLJ Report. Failure to develop those reserves would have a negative impact on future earnings.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenues to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property uneconomic.

## Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

The following tables disclose, by each product type, the volumes of proved and probable undeveloped reserves that were first attributed by GLJ in each of the most recent three financial years.

***Proved Undeveloped Reserves*** (1)

| | Light Crude Oil and Medium Crude Oil (Mbbl) | | Tight Oil (Mbbl) | | Conventional Natural Gas (Bcf) | | Shale Gas (Bcf) | |
|---|---|---|---|---|---|---|---|---|
| | First Attributed | Total at Year-end | First Attributed | Total at Year-end | First Attributed | Total at Year-end | First Attributed | Total at Year-end |
| 2020 | — | 5,349 | 3,627 | 8,499 | — | 78.2 | 244.0 | 1,448.0 |
| 2021 | — | — | 1,262 | 8,048 | — | — | 1,298.8 | 2,467.3 |
| 2022 | — | — | 1,109 | 5,420 | — | — | 380.5 | 2,320.6 |

| | NGLs (Mbbl) | | Total (Mboe) | |
|---|---|---|---|---|
| | First Attributed | Total at Year-end | First Attributed | Total at Year-end |
| 2020 | 14,114 | 49,694 | 58,415 | 317,910 |
| 2021 | 173,397 | 213,183 | 391,121 | 632,450 |
| 2022 | 35,408 | 171,933 | 99,932 | 564,118 |

***Probable Undeveloped Reserves*** (1)

| | Light Crude Oil and Medium Crude Oil (Mbbl) | | Tight Oil (Mbbl) | | Conventional Natural Gas (Bcf) | | Shale Gas (Bcf) | |
|---|---|---|---|---|---|---|---|---|
| | First Attributed | Total at Year-end | First Attributed | Total at Year-end | First Attributed | Total at Year-end | First Attributed | Total at Year-end |
| 2020 | — | 2,988 | 2,023 | 9,292 | — | 7.0 | 221.4 | 1,095.4 |
| 2021 | — | — | 358 | 8,396 | — | — | 774.7 | 1,613.2 |
| 2022 | — | — | 1,503 | 8,144 | — | — | 302.0 | 1,600.7 |

| | NGLs (Mbbl) | | Total (Mboe) | |
|---|---|---|---|---|
| | First Attributed | Total at Year-end | First Attributed | Total at Year-end |
| 2020 | 14,305 | 40,796 | 53,225 | 236,815 |
| 2021 | 107,186 | 140,923 | 236,667 | 418,181 |
| 2022 | 54,011 | 159,466 | 105,840 | 434,393 |

1) There are no undeveloped reserves attributed to Heavy Oil in the last three years.

As of December 31, 2022, undeveloped reserves represented 47 per cent of total proved reserves and 55 per cent of proved plus probable reserves. Over 44 per cent of the proved plus probable undeveloped reserves are located in the Kakwa area, with the rest located in our Montney assets in northeast British Columbia and other areas in northern Alberta. We have planned a program to develop a portion of the undeveloped reserves in 2023 and 2024, focusing on the Kakwa, Greater Dawson, Sunrise, and Ante Creek areas.

Reserves were assigned adhering to the practices outlined within the COGE Handbook, with uncertainty applied at the individual location level to account for the potential variability in well results. There were 627 total proved, undeveloped locations assigned to be developed in ARC's core properties over the next nine years in the 2022 evaluation which account for 564 MMboe of reserves volumes. 87 per cent of the total proved FDC is forecasted to be spent in the next five years. In addition to these total proved undeveloped locations are 261 future development locations assigned probable reserves only, an incremental 46 per cent, with a timeline to develop these reserves over the next nine years. 74 per cent of the total proved plus probable FDC is forecasted to be spent in the next five years. These probable locations and additional probable reserves assigned to proved locations account for 434 MMboe. The total proved plus probable undeveloped volumes account for 998 MMboe and are all scheduled to produce within the capacity of existing facilities or facilities to which capital has been assigned within the reserves evaluation. Due to these facility capacity limitations, the proved and probable undeveloped reserves are scheduled to be produced beyond a two-year time frame. Consistent with ARC's principles to maintain a strong balance sheet and demonstrate capital discipline, capital forecasts in the GLJ Report do not exceed levels historically demonstrated by ARC in any given year.

The pace of development of the proved and probable undeveloped reserves, both in 2023 and 2024, as well as in years beyond 2024, is influenced by many other factors, including the outcomes of the annual drilling and reservoir evaluations, the price for crude oil and natural gas, and a variety of economic factors and conditions.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating, and capital expenditure fluctuations, or changing regulation and/or fiscal or environmental policy); (ii) changing technical conditions (including production anomalies, such as accelerated depletion); (iii) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (iv) surface access issues (including those relating to land owners, weather conditions, and regulatory approvals). For more information as to the risks involved, refer to the section entitled "*Risk Factors*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

## Significant Factors or Uncertainties Affecting Reserves Data

We have a significant amount of proved undeveloped and probable undeveloped reserves assigned to the Montney. Sophisticated technology and large capital expenditures are required to bring these undeveloped reserves into production.

Degradation in future commodity price forecasts relative to the forecast in the GLJ Report may have a negative impact on the economics and timing of the development of undeveloped reserves, unless significant reduction in the future costs of development are realized.

The failure to obtain all necessary licenses, permits, and other approvals to carry out exploration, development, and operating activities on ARC's assets would negatively impact the economics and timing of developing ARC's undeveloped reserves. See the sections entitled "*Risk Factors - Indigenous Land and Rights Claims*" and "*Risk Factors - Regulatory Approvals*" within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

The following table sets forth information respecting anticipated future abandonment and reclamation costs for surface leases, wells, facilities, and pipelines, including those where reserves are attributed. These abandonment and reclamation costs have been calculated outside of the reserves process and exclude any costs for undeveloped reserves. As at December 31, 2022, ARC had 2,922 net wells for which we expect to incur abandonment and reclamation costs.

| Abandonment and Reclamation Costs Escalated at an average of 2.0% | Undiscounted ($ millions) | Discounted at 10% (1) ($ millions) |
|---|---|---|
| Total as at December 31, 2022 | 537.1 | 142.7 |
| Anticipated to be paid in 2023 | 16.4 | 15.2 |
| Anticipated to be paid in 2024 | 15.0 | 12.9 |
| Anticipated to be paid in 2025 | 15.0 | 12.0 |

1) Costs used to determine ARC's asset retirement obligation in the financial statements have been discounted using a liability-specific risk-free rate of 3.3 per cent.

For more information with respect to our reclamation and abandonment obligations for properties with no attributed reserves, see "*Statement of Reserves Data and Other Oil and Gas Information - Properties with no Attributed Reserves*" contained within this Annual Information Form. In addition, see the section entitled "*Further Information Respecting Abandonment Obligations*" below.

## Further Information Respecting Abandonment Obligations

Abandonment and reclamation costs are incurred to restore shut-in and producing wells, facilities, and pipelines that have been disturbed by ARC's operations to the standard imposed by the applicable regulatory authorities. We include abandonment and reclamation costs for our property, plant and equipment ("PP&E") and exploration and evaluation assets ("E&E") in our annual budgeting process for the budget year and a provision for these costs is recognized at the present value of Management's best estimate of total expenditures required to settle the liability as at the date of the balance sheet. These ongoing environmental obligations are expected to be provided for with funds from operations. A portion of the liability is settled each year and facilities are scheduled to be decommissioned once all of the wells associated with a particular facility have been suspended or abandoned. Our model for estimating the amount and timing of future abandonment and reclamation expenditures was created at an operating area level. Estimated expenditures for each operating area are based on numerous sources, including information provided by provincial regulatory authorities, industry peer groups, area-specific data from a third-party liability management firm, and proprietary data from our operations. All wells, pipelines, facilities, and associated costs are then assigned to a specific geographic region which is consistent with the methodology used by the Alberta Energy Regulator ("AER") and the British Columbia Energy Regulator ("BCER"). No estimate of salvage value is netted against the estimated cost. The estimates are reviewed periodically, and any changes are applied prospectively.

The provision for site restoration and abandonment is based on current legal and constructive requirements, technology, price levels, and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions, and changes in technology. For more information, see Note 5 "*Management Judgments and Estimation Uncertainty*" in the financial statements, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

In estimating the future net revenues disclosed in this Annual Information Form, the GLJ Report, in the proved plus probable category, deducted $964 million (undiscounted) and $66 million (discounted at 10 per cent) for abandonment and reclamation costs for all active assets with attributed reserves. Refer to Note 15 "*Asset Retirement Obligation*" in the financial statements and to the section entitled "*Asset Retirement Obligation*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

# Core Operating Areas

The following is a description of ARC's principal crude oil and natural gas properties as at December 31, 2022. Information in respect of gross and net acres and well counts are as at December 31, 2022. Due to the fact that ARC has been actively acquiring additional interests in its core operating areas (and divesting of non-core assets), the working interest in gross/net acres and wells as at December 31, 2022 may not directly correspond to the stated production for the year, which only includes production after (or up to) the date the interests were acquired (or divested) by ARC.

ARC's crude oil and natural gas properties described below are all located in the Western Canadian Sedimentary Basin and onshore within the Canadian provinces of Alberta and British Columbia. Except as set forth under the heading "*Statement of Reserves Data and Other Oil and Gas Information - Undeveloped Reserves*", there are no material districts to which reserves have been attributed that are capable of producing but which are not producing at December 31, 2022, and there are no material statutory or mandatory relinquishments, surrenders, back-ins, or changes in ownership provisions. When determining gross and net acreage for two or more lease agreements covering the same lands but different rights, the acreage is reported for each lease agreement.

## Alberta

ARC's assets in northern Alberta are predominantly located in the Montney formation. ARC is one of the largest operators in the region with an average working interest of 92 per cent in approximately 352,525 gross hectares (322,860 net hectares), which includes land holdings of 982 net Montney sections. ARC drilled 125 gross operated wells in 2022 within the region, with an average working interest of 100 per cent. ARC has access to approximately 1,075 MMcf per day of natural gas and 60 Mbbl per day of NGLs processing capacity through facilities in the region.

## British Columbia

ARC's assets in northeast British Columbia are predominantly located in the Montney formation. ARC is one of the largest operators in the region with an average working interest of 98 per cent in approximately 235,763 gross hectares (230,537 net hectares), which includes land holdings of 663 net Montney sections. ARC drilled 11 gross operated wells in 2022 within the region, with an average working interest of 100 per cent. ARC has access to approximately 670 MMcf per day of natural gas processing capacity through its facilities in the region.

# Crude Oil and Natural Gas Wells

The following tables set forth the number and status of wells in which ARC had a working interest as at December 31, 2022.

| **By Province** | **Crude Oil Wells** [1] | | | | **Natural Gas Wells** [2] | | | |
|---|---|---|---|---|---|---|---|---|
| | Producing | | Non-Producing | | Producing | | Non-Producing | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Alberta | 333 | 247 | 205 | 158 | 906 | 835 | 218 | 170 |
| British Columbia | 117 | 116 | 7 | 6 | 535 | 534 | 109 | 101 |
| Total [3] | 450 | 363 | 212 | 164 | 1,441 | 1,369 | 327 | 271 |

1) Includes Light Crude Oil and Medium Crude Oil wells, Heavy Crude Oil wells, and Tight Oil wells.
2) Includes Conventional Natural Gas wells and Shale Gas wells.
3) Total well count differs from well count provided in our discussion of the asset retirement obligation, as this table excludes abandoned, water source, water injection, and disposal wells.

# Properties with No Attributed Reserves

The following table sets out by province our properties with no attributed reserves as at December 31, 2022.

***Undeveloped Hectares***

| | **Gross** | **Net** |
|---|---|---|
| Alberta | 229,068 | 185,145 |
| British Columbia | 163,635 | 160,429 |
| Total | 392,703 | 345,574 |

Undeveloped properties are lands that have not been assigned reserves; however, in certain of our undeveloped lands, reserves may have been assigned in shallower formations. Undeveloped hectares are mineral agreement specific. The table above includes vertically stacked agreements within the same areal footprint.

ARC has no material work commitments related to our undeveloped hectares in 2023. There are no material expiries in our core holdings in 2023.

***Significant Factors or Uncertainties for Properties with No Attributed Reserves***

ARC's business model focuses on our core operations, with little to no capital allocated to the acquisition, exploration, or development of properties with no attributed reserves. Therefore, there are not expected to be any significant factors or uncertainties that would affect such properties at this time and the abandonment and reclamation costs associated with these properties are not expected to be material.

For information with respect to our reclamation and abandonment obligations for our properties to which reserves have been attributed, see the section entitled "*Statement of Reserves Data and Other Oil and Gas Information - Further Information Respecting Abandonment Obligations*" in this Annual Information Form.

# Forward Contracts and Transportation Commitments

ARC is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates, and interest rates, in the normal course of operations. ARC maintains a risk management program including the use of derivative instruments to reduce the volatility of revenues, increase the certainty of funds from operations, and to protect acquisition and development economics.

The Company may also potentially be exposed to losses in the event of default by the counterparties to our derivative instruments. The risk is managed by diversifying our derivative portfolio amongst a number of investment-grade counterparties, including counterparties within our lending syndicate and by conducting regular credit reviews on all counterparties.

A summary of our financial contracts in respect of hedging activities can be found in Note 17 "*Financial Instruments and Market Risk Management*" in the financial statements and in the section entitled "*Risk Management Contracts*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

A part of our ongoing strategy is to secure transportation capacity to ensure our production moves to market over the short and long term. ARC believes that securing firm takeaway capacity is prudent management of our business, and has secured sufficient takeaway for existing production and anticipated future growth. Our transportation commitments available for future physical deliveries of crude oil, natural gas, and NGLs exceed ARC's expected related future production of our proved reserves, based on the GLJ Report. The amount and estimated cost of excess firm takeaway capacity as compared to our proved reserves forecast is presented in the table below:

| Excess Capacity Above Proved Reserves | Zero to Five Years | Beyond Five Years |
|---|---|---|
| Natural Gas (MMcf/d) | 551 | 244 |
| Crude Oil and NGLs (Mbbl/d) | 10 | 13 |
| Estimated Cost ($ millions) | 524 | 798 |

Total proved reserves comprise 66 per cent of total proved plus probable reserves. If ARC's sales volumes were equivalent to the forecast production of proved plus probable reserves, the amount and estimated cost of excess firm takeaway capacity as compared to our expected related production from our proved plus probable reserves is presented in the table below:

| Excess Capacity Above Proved Plus Probable Reserves | Zero to Five Years | Beyond Five Years |
|---|---|---|
| Natural Gas (MMcf/d) | 431 | 209 |
| Crude Oil and NGLs (Mbbl/d) | — | — |
| Estimated Cost ($ millions) | 370 | 553 |

In cases where ARC holds transportation commitments for volume that exceeds its expected future production from proved and proved plus probable reserves, it has identified contractual opportunities where it may reduce its exposure to negative cash flows arising from the settlements of these contractual obligations. Additionally, ARC expects to fulfill these commitments through ongoing exploration and development activities, subject to our development plans, well performance, and disruptions or constraints at facilities and pipelines.

Additional disclosure related to such commitments, as well as ARC's other financial contracts as at December 31, 2022, are set forth in Note 22 "*Commitments and Contingencies*" in the financial statements, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

# Tax Horizon

We expect to allocate our funds from operations towards capital expenditures, periodic debt repayments, site reclamation expenditures, cash payments to shareholders in the form of dividends and share repurchases, and potential net acquisitions of undeveloped land and production. Taxable income varies depending on total income and expenses and varies with changes to commodity prices, costs, claims of both accumulated tax pools, and tax pools associated with current year expenditures, acquisitions, and dispositions.

ARC has accumulated $4.5 billion of income tax pools for federal tax purposes at December 31, 2022. In 2022, ARC recognized a current income tax expense of $288.5 million. For 2023, ARC expects current income tax expense to range from 10 per cent to 15 per cent of funds from operations(1); however, this will be dependent on the commodity price environment and the amount of capital invested. For more information, please see Note 18 "*Income Taxes*" in the financial statements, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

1) For information on this supplementary financial measure refer to the section entitled *"Non-GAAP and Other Financial Measures"* contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

# Costs Incurred

The following table summarizes costs incurred for the year ended December 31, 2022.

| ($ millions) | Alberta | British Columbia | Total |
|---|---|---|---|
| Property Acquisition (Disposition) Costs, Net [1] | | | |
| Proved Properties | (9.5) | 0.1 | (9.4) |
| Unproved Properties | — | 0.3 | 0.3 |
| Exploration Costs [2] | — | 6.4 | 6.4 |
| Development Costs [3] | 1,128.9 | 251.5 | 1,380.4 |
| **Total** | **1,119.4** | **258.3** | **1,377.7** |

1) Represents acquisition costs net of disposition proceeds and property swaps, and includes costs of land acquired ($2.4 million). Acquisition value is net of post-closing adjustments. Disposition value represents proceeds and adjustments to proceeds from divestitures.
2) Represents asset additions that have been determined by Management to be in the E&E stage and excludes capitalized corporate costs.
3) Represents additions to PP&E and excludes capitalized corporate costs.

# Exploration and Development Activities

The following table sets forth the gross and net development wells that ARC participated in during the year ended December 31, 2022.

| By Well Type | Development Wells [1][2] | |
|---|---|---|
| | Gross | Net |
| Crude Oil | 19 | 19 |
| Natural Gas | 115 | 115 |
| Service Well | 1 | 1 |
| Dry | 1 | 1 |
| **Total** | **136** | **136** |

1) Number of wells based on rig release dates. Total well count differs from well count provided in the section entitled *"Cash Flow used in Investing Activities, Capital Expenditures, Acquisitions, and Dispositions'* contained within the MD&A, as all working interest wells are included regardless of well status.
2) ARC did not drill any exploration wells or stratigraphic test wells for the year ended December 31, 2022.

# Production Estimates

The following tables set out the GLJ forecast of the volume of production estimated for the year ended December 31, 2023, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data*".

**TOTAL PROVED**

| | Light Crude Oil & Medium Crude Oil (bbl/d) | | Heavy Crude Oil (bbl/d) | | Tight Oil (bbl/d) | | Conventional Natural Gas (Mcf/d) | | Shale Gas (Mcf/d) | | NGLs (bbl/d) | | Total (boe/d) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Kakwa | — | — | — | — | — | — | 16,467 | 13,453 | 486,628 | 437,347 | 103,035 | 84,758 | 186,884 | 159,891 |
| Other Properties | — | — | 70 | 220 | 8,212 | 6,565 | 1,541 | 1,453 | 687,550 | 583,352 | 18,923 | 15,753 | 142,055 | 120,006 |
| **Total Proved** | **—** | **—** | **70** | **220** | **8,212** | **6,565** | **18,008** | **14,907** | **1,174,178** | **1,020,699** | **121,958** | **100,511** | **328,939** | **279,897** |

**TOTAL PROBABLE**

| | Light Crude Oil & Medium Crude Oil (bbl/d) | | Heavy Crude Oil (bbl/d) | | Tight Oil (bbl/d) | | Conventional Natural Gas (Mcf/d) | | Shale Gas (Mcf/d) | | NGLs (bbl/d) | | Total (boe/d) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Kakwa | — | — | — | — | — | — | 311 | 238 | 55,550 | 50,756 | 10,397 | 8,869 | 19,707 | 17,368 |
| Other Properties | — | — | — | 1 | 1,024 | 767 | 357 | 212 | 46,551 | 40,762 | 2,067 | 1,814 | 10,910 | 9,411 |
| **Total Probable** | **—** | **—** | **—** | **1** | **1,024** | **767** | **668** | **449** | **102,101** | **91,518** | **12,464** | **10,683** | **30,617** | **26,779** |

**TOTAL PROVED PLUS PROBABLE**

| | Light Crude Oil & Medium Crude Oil (bbl/d) | | Heavy Crude Oil (bbl/d) | | Tight Oil (bbl/d) | | Conventional Natural Gas (Mcf/d) | | Shale Gas (Mcf/d) | | NGLs (bbl/d) | | Total (boe/d) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Kakwa | — | — | — | — | — | — | 16,778 | 13,691 | 542,177 | 488,103 | 113,432 | 93,626 | 206,591 | 177,259 |
| Other Properties | — | — | 71 | 221 | 9,236 | 7,332 | 1,898 | 1,665 | 734,101 | 624,114 | 20,991 | 17,567 | 152,964 | 129,417 |
| **Total Proved plus Probable** | **—** | **—** | **71** | **221** | **9,236** | **7,332** | **18,676** | **15,356** | **1,276,278** | **1,112,217** | **134,423** | **111,193** | **359,556** | **306,676** |

The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

## Production History

The following tables summarize certain information in respect of our production, product prices received, royalties paid, operating expense, transportation expense, and the resulting netback for the periods indicated below:

| Production History | Three Months Ended 2022 | | | | Year Ended |
|---|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 | 2022 |
| Average Daily Production [(1)] | | | | | |
| Light and Medium Crude Oil (bbl/d) | 1,363 | 1,068 | 1,065 | 998 | 1,122 |
| Heavy Crude Oil (bbl/d) | 138 | 138 | 225 | 252 | 189 |
| Tight Oil (bbl/d) | 6,391 | 7,091 | 6,859 | 6,030 | 6,593 |
| Conventional Natural Gas (MMcf/d) | 456.7 | 430.0 | 429.3 | 468.2 | 446.0 |
| Shale Gas (MMcf/d) | 823.4 | 788.8 | 798.1 | 841.5 | 813.0 |
| NGLs (bbl/d) [(2)] | 123,213 | 124,670 | 129,311 | 134,166 | 127,874 |
| Condensate (bbl/d) | 72,956 | 75,793 | 82,203 | 82,855 | 78,489 |
| Other NGLs (bbl/d) [(3)] | 50,257 | 48,877 | 47,108 | 51,311 | 49,385 |
| Total (boe/d) | 344,447 | 336,112 | 342,034 | 359,730 | 345,613 |
| Average Net Production Prices Received | | | | | |
| Light and Medium Crude Oil ($/bbl) | 129.77 | 150.39 | 123.88 | 122.17 | 131.55 |
| Heavy Crude Oil ($/bbl) | 100.33 | 90.22 | 83.41 | 63.03 | 80.84 |
| Tight Oil ($/bbl) | 107.82 | 133.00 | 110.39 | 102.20 | 113.95 |
| Conventional Natural Gas ($/Mcf) | 6.66 | 8.64 | 11.00 | 10.16 | 9.12 |
| Shale Gas ($/Mcf) | 5.60 | 9.32 | 8.37 | 7.28 | 7.62 |
| NGLs ($/bbl) [(2)] | 81.95 | 97.23 | 77.70 | 77.26 | 83.34 |
| Condensate ($/bbl) | 119.15 | 137.91 | 110.35 | 107.24 | 118.17 |
| Other NGLs ($/bbl) [(3)] | 27.94 | 34.16 | 20.72 | 28.86 | 27.98 |
| Total ($/boe) | 54.10 | 72.31 | 65.37 | 61.17 | 63.18 |
| Royalties Paid | | | | | |
| Light and Medium Crude Oil ($/bbl) | 7.64 | 8.38 | 6.12 | 8.72 | 7.69 |
| Heavy Crude Oil ($/bbl) | 0.09 | (1.38) | 0.16 | 0.05 | (0.17) |
| Tight Oil ($/bbl) | 20.90 | 28.53 | 24.67 | 26.55 | 25.24 |
| Conventional Natural Gas ($/Mcf) | 0.29 | 0.36 | (0.60) | 0.22 | 0.07 |
| Shale Gas ($/Mcf) | 0.65 | 1.15 | 1.40 | 1.57 | 1.20 |
| NGLs ($/bbl) [(2)] | 15.25 | 19.75 | 16.40 | 15.42 | 16.68 |
| Condensate ($/bbl) | 23.30 | 29.38 | 23.11 | 22.53 | 24.51 |
| Other NGLs ($/bbl) [(3)] | 3.56 | 4.82 | 4.69 | 3.93 | 4.24 |
| Total ($/boe) | 7.81 | 11.10 | 9.23 | 10.18 | 9.59 |
| Operating Expense [(4)] | | | | | |
| Light and Medium Crude Oil ($/bbl) | 6.74 | 9.64 | 8.87 | 8.37 | 8.24 |
| Heavy Crude Oil ($/bbl) | 0.30 | 0.06 | 10.77 | 9.01 | 9.16 |
| Tight Oil ($/bbl) | 6.57 | 5.04 | 6.95 | 6.21 | 6.19 |
| Conventional Natural Gas ($/Mcf) | 0.81 | 1.00 | 0.97 | 1.02 | 0.94 |
| Shale Gas ($/Mcf) | 0.52 | 0.61 | 0.58 | 0.42 | 0.53 |
| NGLs ($/bbl) [(2)] | 4.41 | 4.91 | 5.16 | 5.14 | 4.93 |
| Condensate ($/bbl) | 4.51 | 4.92 | 5.27 | 4.94 | 4.91 |
| Other NGLs ($/bbl) [(3)] | 4.27 | 4.91 | 4.96 | 5.46 | 4.97 |
| Total ($/boe) | 4.04 | 4.66 | 4.69 | 4.37 | 4.44 |

| Production History - continued | Three Months Ended 2022 | | | | Year Ended |
|---|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 | 2022 |
| Transportation Expense | | | | | |
| Light and Medium Crude Oil ($/bbl) | 4.66 | 10.24 | 23.29 | 17.07 | 13.22 |
| Heavy Crude Oil ($/bbl) | — | — | 0.03 | 0.24 | 0.09 |
| Tight Oil ($/bbl) | 3.37 | 4.07 | 2.87 | 3.74 | 3.51 |
| Conventional Natural Gas ($/Mcf) | 2.15 | 2.15 | 2.07 | 1.84 | 2.05 |
| Shale Gas ($/Mcf) | 0.67 | 0.75 | 0.83 | 0.74 | 0.75 |
| NGLs ($/bbl) (2) | 2.91 | 4.44 | 3.74 | 3.94 | 3.77 |
| Condensate ($/bbl) | 4.21 | 5.43 | 4.36 | 4.58 | 4.64 |
| Other NGLs ($/bbl) (3) | 1.02 | 2.90 | 2.67 | 2.92 | 2.38 |
| Total ($/boe) | 5.57 | 6.27 | 6.08 | 5.70 | 5.90 |
| Netback Received | | | | | |
| Light and Medium Crude Oil ($/bbl) | 110.73 | 122.13 | 85.60 | 88.01 | 102.40 |
| Heavy Crude Oil ($/bbl) | 99.94 | 91.54 | 72.45 | 53.73 | 71.76 |
| Tight Oil ($/bbl) | 76.98 | 95.36 | 75.90 | 65.70 | 79.01 |
| Conventional Natural Gas ($/Mcf) | 3.41 | 5.13 | 8.56 | 7.08 | 6.06 |
| Shale Gas ($/Mcf) | 3.76 | 6.81 | 5.56 | 4.55 | 5.14 |
| NGLs ($/bbl) (2) | 59.38 | 68.13 | 52.40 | 52.76 | 57.96 |
| Condensate ($/bbl) | 87.13 | 98.18 | 77.61 | 75.19 | 84.11 |
| Other NGLs ($/bbl) (3) | 19.09 | 21.53 | 8.40 | 16.55 | 16.39 |
| Total ($/boe) | 36.68 | 50.28 | 45.37 | 40.92 | 43.25 |

1) Before deduction of royalties and including royalty interests.
2) NGLs as defined by GLJ which includes condensate, butane, ethane, and propane.
3) Other NGLs as defined by ARC includes butane, ethane, and propane but excludes condensate.
4) Operating expense is comprised of direct costs incurred to operate both crude oil and natural gas wells. A number of assumptions have been made in allocating these costs between crude oil, natural gas, condensate, and NGLs production.

Alberta and British Columbia account for approximately 58 per cent and 42 per cent, respectively, of the total production disclosed above. For more information, see the section entitled "*Statement of Reserves Data and Other Oil and Gas Information*" of this Annual Information Form.

# SHARE CAPITAL OF ARC RESOURCES

The authorized capital of ARC Resources is an unlimited number of common shares without nominal or par value and 50,000,000 preferred shares without nominal or par value issuable in series of which 620,887,956 common shares and no preferred shares were outstanding as at December 31, 2022.

The following is a summary of the rights, privileges, restrictions, and conditions which attach to the share capital of ARC Resources.

## Common Shares

Holders of common shares are entitled to notice of, to attend, and to one vote per share held at any meeting of the shareholders of the Corporation (other than meetings of a class or series of shares of the Corporation other than the common shares as such).

Holders of common shares are entitled to receive dividends as and when declared by the Board of Directors of the Corporation on the common shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of the Corporation ranking in priority to the common shares in respect of dividends.

Holders of common shares are entitled in the event of any liquidation, dissolution, or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the common shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of the Corporation ranking equally with the common shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

## Preferred Shares

Preferred shares may at any time or from time to time be issued in one or more series. Before any shares of a particular series are issued, the Board of Directors shall, by resolution, fix the number of shares that will form such series and shall, subject to the limitations set out in ARC Resources' articles, by resolution fix the designation, rights, privileges, restrictions, and conditions to be attached to the preferred shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for securities of ARC Resources or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than preferred shares or payment in respect of capital on any shares in the capital of ARC Resources or creation or issue of debt or equity securities. Notwithstanding the foregoing, other than in the case of a failure to declare or pay dividends specified in any series of preferred shares, the voting rights attached to the preferred shares shall be limited to one vote per preferred share at any meeting where the preferred shares and common shares vote together as a single class.

Any preferred shares of ARC Resources are intended to provide future financing flexibility and are not intended to be used to block any takeover bid for ARC Resources. ARC Resources confirms that it will not, without prior shareholder approval, issue any preferred shares for any anti-takeover purpose.

## Normal Course Issuer Bid

ARC established an NCIB on September 1, 2021, allowing the Company to purchase 72.2 million of its outstanding common shares, representing 10 per cent of its public float, over a 12-month period ending August 31, 2022. Subsequently, ARC renewed its NCIB on September 1, 2022, allowing the Company to purchase up to 65.3 million of its outstanding common shares, representing 10 per cent of its public float, over a 12-month period ending August 31, 2023. Under the NCIB, common shares may be purchased in open market transactions on the TSX and other alternative trading platforms in Canada and in accordance with the TSX rules for NCIBs. Any common shares that are purchased under the NCIB will be cancelled. For the 12-month period ending December 31, 2022, ARC had repurchased a total of 74.6 million common shares pursuant to the NCIB.

# OTHER INFORMATION RELATING TO OUR BUSINESS

## Borrowing

ARC borrows funds periodically for capital expenditures, to finance the purchase of assets, or for other financial obligations or expenditures in respect of assets held by us or for working capital purposes. ARC's long-term strategy is to target the ratio of net debt to funds from operations[(1)] between 1.0 to 1.5 times. The level of borrowing is assessed regularly by Management and is subject to quarterly reviews by the Board of Directors of ARC Resources.

Our borrowings comprise both a bank credit facility and unsecured notes. We may choose to repay a portion of our debt from one source and borrow from other parties in order to reduce borrowing costs and provide more financial flexibility.

As at December 31, 2022, we had a $1.8 billion unsecured credit facility with a syndicate of major chartered banks, a $40.0 million working capital facility with our agent bank, a $15.0 million letter of credit facility with our agent bank, a $25.0 million letter of credit facility with another major chartered bank and member of the syndicate, and $1.0 billion of senior notes outstanding. ARC had a net debt[(1)] balance of $1.3 billion outstanding at December 31, 2022, comprised of $990.0 million of long-term debt, and a working capital deficit of $311.5 million.

Borrowings under the facility bear interest at Canadian bank prime or US base rate, or Canadian dollar bankers' acceptances or US dollar loan rates, plus applicable margin and stamping fees, which are based on ARC's credit rating. The maturity date of the credit facility is October 28, 2026. In the event the credit facility is not extended at any time before the maturity date, the loan will become repayable on the maturity date.

The senior notes outstanding were issued in two tranches with maturity dates of March 10, 2026 and March 10, 2031 and bear interest at a fixed rate.

ARC is in compliance in all material respects with the terms of the agreements governing the credit facilities and senior notes described above, and has maintained this status throughout the Corporation's history.

The credit facilities and senior notes rank equally and contain provisions which restrict the payment of dividends to shareholders, in the event of the occurrence of certain events of default. For more information, refer to Note 13 "*Long-term Debt*" in the financial statements, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

## Credit Ratings

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.

### DBRS

The DBRS long-term debt rating scale provides an opinion on the risk of default, meaning the risk that an issuer will fail to satisfy its financial obligations in accordance with the terms under which an obligation has been issued. Ratings are based on quantitative and qualitative considerations relevant to the issuer, and the relative ranking of claims. All rating categories, other than AAA and D, contain subcategories "(high)" or "(low)". The absence of either a "(high)" or "(low)" designation indicates the rating is in the middle of the category.

As of December 31, 2022, DBRS has assigned ARC a BBB issuer rating (stable trend). DBRS has also assigned a BBB rating (stable trend) on ARC's outstanding senior unsecured notes.

### Payments to Credit Rating Organizations

ARC has made payments to, and reasonably expects, from time to time, to continue to make customary payments to DBRS for the provision of the related ratings and other services.

(1) For information on this capital management measure refer to Note 16 "*Capital Management*" of the financial statements and to the section entitled "*Non-GAAP and Other Financial Measures*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

# Sustainability

ARC is committed to the responsible development of our assets and integrating principles of sustainability into all aspects of our business. Through strong ESG performance and delivering value to our stakeholders and Indigenous communities, our goal is to be Canada's "Best-in-Class Responsible Energy Producer". With a long-term vision and 26-year history, we are dedicated to building a sustainable business that supports the transition to a low-carbon economy. Our approach prioritizes producing low-cost, low-emissions energy, while supporting the economic and social well-being of the communities in which we work. This approach to responsible development has shaped the company we are today, and underpins our strategy for continued success into the future.

## ESG Guiding Principles

We manage our business for the long term and strive to achieve leading ESG performance with a focus on the following guiding principles relating to environmental performance: i) provide low-carbon energy for the future, ii) protect ARC's water resources – "Secure, Reduce, Recycle", and iii) restore land; relating to social performance: i) be an industry leader in health, safety, and environmental practices and performance, ii) form strong relationships with Indigenous communities, iii) create shared value for society, and iv) develop a diverse and inclusive workforce; and relating to governance performance: i) ensure appropriate focus and oversight on ESG strategies and practices, ii) continually improve governance structure and processes, and iii) ensure a strong link between executive compensation and performance, including the assessment of ESG metrics.

## Disclosure

We recognize the importance of comprehensive and transparent disclosure of our progress towards stated ESG goals and targets. To support our disclosure efforts, we publish a comprehensive biennial ESG Report to measure and report on our performance, with performance updates occurring in the years between. In 2022, we published our most recent ESG Report. The report covers prioritized key ESG topics with consideration of their impact on enterprise value, ARC's business activities, and risk management.

Where possible, we measure our performance by aligning to internationally recognized standards and frameworks, including the Task Force on Climate-related Financial Disclosures, Sustainability Accounting Standards Board, and Global Reporting Initiative reporting frameworks.

To support ongoing transparency and assurance of our sustainability practices and performance, ARC has maintained its certification under the EO100™ Standard for Responsible Energy Development at our Kakwa asset. In 2022, ARC also achieved this certification for our northeast British Columbia assets, and in January 2023 achieved certification for our Ante Creek assets. These certifications were granted following a comprehensive and independent process that included site-level assessments and interviews with key stakeholders and Indigenous communities. Certification under this global standard acknowledges ARC's top-tier ESG performance and commitment to continuous improvement.

For more information on ARC's ESG performance and for the most recent ESG Report, see www.arcresources.com/responsibility.

# DIRECTORS AND EXECUTIVE OFFICERS

## Directors

The name, municipality, province and country of residence, positions held, period during which such positions have been held, and principal occupation during the past five years of each current Director of ARC Resources as at March 9, 2023 are set out below.

| **Directors** [(1)] | | |
|---|---|---|
| **Name and Municipality of Residence** | **Director Since** [(2)] | **Principal Occupation During Past Five Years** |
| **Harold N. Kvisle**<br>Calgary, Alberta, Canada | 2009 (Chair)<br>Independent | Mr. Kvisle is an independent businessperson. |
| **Farhad Ahrabi**<br>Houston, Texas, USA | 2019<br>Independent | Mr. Ahrabi is the President and Chief Executive Officer of Commonwealth LNG, a company engaged in the development of LNG export facilities. From 2014 to 2022, he held the position of Chief Executive Officer at Cameron LNG LLC. |
| **Carol T. Banducci**<br>Mississauga, Ontario, Canada | 2021<br>Independent | Ms. Banducci is an independent businessperson. Prior to March 2021, she held the position of Executive Vice President and Chief Financial Officer of IAMGOLD Corporation. |
| **David R. Collyer**<br>Calgary, Alberta, Canada | 2016<br>Independent | Mr. Collyer is an independent businessperson. |
| **William J. McAdam**<br>Scottsdale, Arizona, USA | 2021<br>Independent | Mr. McAdam is an independent businessperson. |
| **Michael G. McAllister**<br>Calgary, Alberta, Canada | 2020<br>Independent | Mr. McAllister is an independent businessperson. Prior to 2020, he held the position of Executive Vice President and Chief Operating Officer of Ovintiv Inc. (formerly Encana Corporation). |
| **Marty L. Proctor**<br>Calgary, Alberta, Canada | 2021<br>Non-independent | Mr. Proctor is the former President and Chief Executive Officer of Seven Generations, a position he held from July 2017 to April 2021. |
| **M. Jacqueline Sheppard**<br>Calgary, Alberta, Canada | 2021<br>Independent | Ms. Sheppard is an independent businessperson. |
| **Leontine van Leeuwen-Atkins**<br>Calgary, Alberta, Canada | 2021<br>Independent | Ms. Atkins is an independent businessperson. Prior to 2020, she was a Partner at KPMG Canada. |
| **Terry M. Anderson**<br>Calgary, Alberta, Canada | 2020<br>Management Director | Mr. Anderson is the President and Chief Executive Officer of ARC Resources. Prior to February 2020, he was the Senior Vice President and Chief Operating Officer of ARC Resources. |

1) Susan C. Jones retired as a director of ARC on February 28, 2023.
2) The term of each director is until the next annual meeting of shareholders.

As at December 31, 2022, the Directors and Officers of ARC Resources, as a group, beneficially owned or controlled 3,221,104 common shares or approximately 0.52 per cent of the outstanding common shares.

## Executive Officers

The name, municipality, province and country of residence, position held, and principal occupation during the past five years of each executive officer of ARC Resources as at March 9, 2023 are set out below.

| **Officers** | |
|---|---|
| **Name and Municipality of Residence** | **Office Held and Principal Occupation During Past Five Years** |
| **Terry M. Anderson**<br>Calgary, Alberta, Canada | **President and Chief Executive Officer**<br>Mr. Anderson is the President and Chief Executive Officer. Prior to February 2020, he was the Senior Vice President and Chief Operating Officer. |
| **Kristen J. Bibby**<br>Calgary, Alberta, Canada | **Senior Vice President and Chief Financial Officer**<br>Mr. Bibby is the Senior Vice President and Chief Financial Officer. Prior to February 2020, he was the Vice President, Finance and Capital Markets. |
| **Armin Jahangiri**<br>Calgary, Alberta, Canada | **Senior Vice President and Chief Operating Officer**<br>Mr. Jahangiri is the Senior Vice President and Chief Operating Officer. From April 2021 to January 2022, he was the Senior Vice President, Capital Projects. From March 2017 to April 2021, he held the position of Vice President, Operations. |
| **Larissa M. Conrad**<br>Calgary, Alberta, Canada | **Senior Vice President and Chief Development Officer**<br>Ms. Conrad is the Senior Vice President and Chief Development Officer. From January to December 2021, she was the Senior Vice President, Development. From October to December 2020, she held the position of Vice President, Development and Planning. Prior to October 2020, she was the Vice President, Engineering and Planning. |
| **Ryan V. Berrett**<br>Calgary, Alberta, Canada | **Senior Vice President, Marketing**<br>Mr. Berrett is the Senior Vice President, Marketing. Prior to January 2022, he was the Vice President, Marketing. |
| **Lisa A. Olsen**<br>Calgary, Alberta, Canada | **Senior Vice President, People and Corporate**<br>Ms. Olsen is the Senior Vice President, People and Corporate. From April 2021 to January 2022, she held the position of Vice President, People and Corporate. Prior to April 2021, she was the Vice President, Human Resources. |
| **Sean R. A. Calder**<br>Calgary, Alberta, Canada | **Vice President, Field Operations**<br>Mr. Calder is the Vice President, Field Operations. Prior to September 2022, he was the Vice President, Production. |
| **Kristin L. Cerny**<br>Calgary, Alberta, Canada | **Vice President, Finance**<br>Ms. Cerny is the Vice President, Finance. Prior to April 2021, she was the Manager, Treasury and Risk Management. |
| **Katherine J. Gomes**<br>Calgary, Alberta, Canada | **Vice President, Controller**<br>Ms. Gomes is the Vice President, Controller. Prior to January 2022, she was the Controller. |
| **Brian R. Groundwater**<br>Calgary, Alberta, Canada | **Vice President, Engineering and Geoscience**<br>Mr. Groundwater is the Vice President, Engineering and Geoscience. Prior to March 2022, he was the Vice President, Engineering. From January 2018 to April 2021, he held the position of Manager, Engineering. |
| **Tejay D. Haugen**<br>Calgary, Alberta, Canada | **Vice President, Operations Planning**<br>Mr. Haugen is the Vice President, Operations Planning. Prior to September 2022, he was Manager, Operations Planning. From 2017 to 2020, he held the position of Supervisor, Operations Planning. |
| **Sean W. Stuart**<br>Calgary, Alberta, Canada | **Vice President, Capital Operations**<br>Mr. Stuart is the Vice President, Capital Operations. From April 2017 to September 2021, he held the position of Manager, Completions. |
| **Grant A. Zawalsky** (1)<br>Calgary, Alberta, Canada | **Corporate Secretary**<br>Mr. Zawalsky is the Vice Chairman and Partner at Burnet, Duckworth & Palmer LLP (law firm). Prior to February 2022, he was a Managing Partner. |

1) Mr. Zawalsky is not considered to be an “executive officer” of ARC as defined by NI 51-102 as he does not perform a policy-making function in respect of the Corporation.

## Membership of Board Committees

The following chart sets out the membership of the committees of the Board of Directors as at March 9, 2023.

| Name of Director | Audit | Human Resources & Compensation (1) | Policy & Board Governance | Risk | Safety, Reserves & Operational Excellence (1) |
|---|---|---|---|---|---|
| Farhad Ahrabi | √ | | | Chair | |
| Carol T. Banducci | √ | | √ | | |
| David R. Collyer | | Chair | √ | | √ |
| Harold N. Kvisle (Board Chair) | | | | | |
| William J. McAdam | | | | √ | √ |
| Michael G. McAllister | | √ | | | Chair |
| Marty L. Proctor | | | | √ | √ |
| M. Jacqueline Sheppard | | √ | Chair | | |
| Leontine van Leeuwen-Atkins | Chair | | | √ | |

1) Susan C. Jones was a member of the Human Resources & Compensation and Safety, Reserves & Operational Excellence committees, until her retirement as a director of ARC on February 28, 2023.

All committees are comprised of independent Directors, with the exception of Marty L. Proctor.

## Officer Biographies

The following comprises a brief description of the background of the current Executive Officers of ARC Resources.

### *Terry M. Anderson, B.Sc., P.Eng.*

PRESIDENT AND CHIEF EXECUTIVE OFFICER, DEPENDENT

Mr. Anderson was appointed President and Chief Executive Officer of ARC Resources Ltd. in 2020. In his role, Mr. Anderson has overall accountability for the Company's strategy and long-term business plans focused on delivering strong financial, operational, and ESG performance. He was appointed to the Board of Directors in May 2020.

Mr. Anderson has more than 30 years' experience working in the North American energy industry. He joined ARC in 2000 after working for six years at a major crude oil and natural gas company. At ARC, he has held progressively senior roles including Senior Vice President and Chief Operating Officer, Senior Vice President, Engineering and Land, and Vice President, Operations. During his tenure, Mr. Anderson played a key role in the Company's transformation from a widespread royalty trust to a highly focused Montney developer. In 2005, he led the technical team credited with unlocking the value of the highly profitable Montney formation by successfully drilling the first horizontal well in the play.

From 2015 to 2020, he was ARC's Senior Vice President and Chief Operating Officer where he led the Company's Montney development and production activities in northeast British Columbia and northern Alberta. Most recently, as President and Chief Executive Officer, Mr. Anderson led the transformational Business Combination with Seven Generations, which resulted in the Company becoming the largest pure-play Montney producer and Canada's third-largest natural gas producer.

Mr. Anderson is active in several organizations including the Canadian Gas Association and the Canadian Association of Petroleum Producers. He holds a Bachelor of Science degree in Petroleum Engineering from the University of Wyoming. He is a member of the Association of Professional Engineers and Geoscientists of Alberta and British Columbia.

### *Kristen J. Bibby, B. Comm, CPA, CA*

SENIOR VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

As Senior Vice President and Chief Financial Officer, Mr. Bibby oversees the Company's financial and risk management activities in support of ARC's strategic priorities. He was appointed to this role in February 2020 and has played a key role in ensuring ARC's financial strength and continued focus on shareholder returns. Mr. Bibby has more than 20 years' experience in finance and accounting roles within the energy industry. He joined ARC in 2014 as Vice President, Finance where he led the finance, tax, and risk management functions. His responsibility increased with the addition of capital markets and investor relations in 2019. Previously, he was Chief Financial Officer at a junior crude oil and natural gas company with international operations.

In 2020, Mr. Bibby was recognized as the Best Investor Relations Officer by IR Magazine Awards. He is a member of the Alberta Chartered Professional Accountants. He has a Bachelor of Commerce degree from the University of Saskatchewan.

### *Armin Jahangiri, P.Eng.*

SENIOR VICE PRESIDENT AND CHIEF OPERATING OFFICER

As Senior Vice President and Chief Operating Officer, Mr. Jahangiri is responsible for ARC's capital operations and production activities, ensuring the Company's ongoing commitment to operational excellence. In addition, he has accountability for ARC's environmental performance, health and safety, regulatory, government relations, and Indigenous relations functions. Mr. Jahangiri has more than 25 years of domestic and international experience in the energy industry with a focus in major project planning, development, and execution. He joined ARC in 2014 and has held increasingly senior roles with an operations and engineering focus. Prior to his appointment as Chief Operating Officer, he served as Vice President, Operations from 2017 to 2021. Prior to ARC, he held development, operations, and production engineering positions with a major Canadian crude oil and natural gas producer, as well as field engineering and operations management positions both onshore and offshore for a global oilfield services company.

Currently, he serves as a director on the board of the University of Calgary Alumni Association. Mr. Jahangiri is a member of the Association of Professional Engineers and Geoscientists of Alberta ("APEGA") and British Columbia ("EGBC"). He holds a Bachelor of Science in Mechanical Engineering from the Sharif University of Technology, and a Master of Engineering in Chemical and Petroleum Engineering with specialization in Reservoir Characterization from the University of Calgary.

### *Larissa M. Conrad, P. Eng.*

SENIOR VICE PRESIDENT AND CHIEF DEVELOPMENT OFFICER

As Senior Vice President and Chief Development Officer, Ms. Conrad is responsible for connecting ARC's subsurface development of our core operations with ARC's business development activities and capital plan to enhance our long-term strategy. With 25 years of energy industry experience, Ms. Conrad brings technical and strategic expertise in all aspects of the energy lifecycle from exploration to production. After she joined ARC in 2011, she has taken on various technical and leadership roles including leadership of engineering, geosciences, joint ventures, mineral land, business development, strategic planning, reserves, and legal. Most recently, she was ARC's Senior Vice President, Development from January to December 2021. Prior to joining ARC, she led fiscal, regulatory, and environmental policy at a major Canadian crude oil and natural gas producer, and held various development, production and field engineering positions prior to that.

In 2020, Ms. Conrad was named to the Global Female Influencer 275 list by the Energy Council. She was the 2022 United Way of Calgary and Area Campaign Co-Chair and has been an active volunteer with the United Way for more than five years. She has a Bachelor of Applied Science degree in Mechanical Engineering from the University of Waterloo; a Certificate of Management Excellence from Harvard Business School, Executive Education; and is a member of APEGA.

### *Ryan V. Berrett, B. Mgmt, MBA*

SENIOR VICE PRESIDENT, MARKETING

As Senior Vice President, Marketing, Mr. Berrett is responsible for ARC's marketing strategy and downstream activities in support of ARC's long-term development plan. In his role, he leads the Company's market access, diversification, and downstream market development initiatives to capture maximum value for each molecule ARC produces and balances enterprise risk. Mr. Berrett joined ARC in 2001. During his tenure, he has developed a deep understanding for ARC's business, holding roles in accounting, finance, and marketing, where he progressed into roles with increasing responsibility. Most recently, he was Vice President, Marketing from 2017 to 2021, where he was responsible for leading ARC's marketing activities including commodity marketing, commercial operations, and downstream market development.

Mr. Berrett has a Bachelor of Management degree from the University of Lethbridge and an Executive MBA in Global Energy from the University of Calgary.

***Lisa A. Olsen, B.A.***
SENIOR VICE PRESIDENT, PEOPLE AND CORPORATE

As Senior Vice President, People and Corporate, Ms. Olsen oversees the Company's corporate functions including governance, human resources, internal communications, and office services. In addition, she is accountable for the Company's ESG reporting and disclosure efforts, with a focus on social and governance practices. With more than 20 years of human resources and corporate experience, Ms. Olsen brings expertise from the domestic and international energy industry and the global consumer industry. Most recently, she served as Vice President, Human Resources from 2016 to 2021. She joined ARC in 2008 as the Manager of Human Resources and has taken on roles of increasing responsibility since. Prior to joining ARC, she spent more than 10 years leading the human resources functions in both a Canadian crude oil and natural gas company with international operations, as well as for a major international consumer brand.

Currently, she serves as Board Chair for Enviros and as an advisory member of the Canadian Centre for Advanced Leadership at the University of Calgary. Ms. Olsen has a Bachelor of Communications from Simon Fraser University and a Certificate of Management Excellence from Harvard Business School, Executive Education.

***Sean R. A. Calder, P.L. (Eng.), R.E.T.***
VICE PRESIDENT, FIELD OPERATIONS

Mr. Calder is ARC's Vice President, Field Operations. In his role, he is responsible for all aspects of field production operations, including production engineering, production systems, maintenance, and asset integrity. He has nearly 30 years of energy industry experience including field operations, drilling and completions, and facility management. Mr. Calder joined ARC in 2005, and since this time has taken on roles of increasing responsibility. Before ARC, he worked at a major crude oil and natural gas company. He is a Professional Licensee (Eng) under APEGA, and a Registered Engineering Technologist ("RET") with the Association of Science and Engineering Technology Professionals in Alberta ("ASET"). Mr. Calder has a Bachelor of Applied Technology Petroleum Engineering degree from the Southern Alberta Institute of Technology.

***Kristin L. Cerny, B.B.A, MSA, CFA***
VICE PRESIDENT, FINANCE

Ms. Cerny is ARC's Vice President, Finance, and is responsible for treasury, corporate finance, insurance, risk management, and market fundamentals analysis. She has more than 20 years of finance experience in capital markets and the energy industry. Ms. Cerny has been with ARC since 2011 in roles of increasing responsibility, most recently as Manager of Treasury and Risk Management. Prior to joining ARC Resources, she worked for two global investment banks in institutional equities in the US for eight years. Currently, she serves on the Board of Directors of WinSport. She holds a Bachelor of Business Administration in Finance from the University of Notre Dame, a Master of Science in Accounting from DePaul University, and is a Chartered Financial Analyst charterholder.

***Katherine J. Gomes, B.Comm, CPA, CA***
VICE PRESIDENT, CONTROLLER

Ms. Gomes is ARC's Vice President, Controller. In her role, she is responsible for the Company's financial reporting, disclosure, internal control, and compliance activities. She has more than 20 years' experience in finance and accounting roles in the energy industry. In 2015, she stepped into the role of Controller and has proactively evolved ARC's reporting and disclosure practices through modernization and technology. Ms. Gomes joined ARC in 2010, leading the financial accounting team with increasing responsibility during her tenure. Prior to joining ARC, she led financial reporting teams at intermediate Canadian energy companies and began her career at an international accounting firm in its audit practice. Ms. Gomes is a member of the Chartered Professional Accountants of Alberta, and she holds a Bachelor of Commerce degree in Accounting from the University of Calgary.

***Brian R. Groundwater, B.Eng, P.Eng***
VICE PRESIDENT, ENGINEERING AND GEOSCIENCE

Mr. Groundwater is the Vice President, Engineering and Geoscience of ARC Resources. In his role, he manages the development engineering, reservoir engineering, and geoscience teams. He has more than 20 years of domestic and international experience in the energy industry, with a depth of technical knowledge of production, facilities, completions, development, and reservoir engineering. Mr. Groundwater joined ARC in 2018, serving as the Manager, Engineering for Alberta and North Montney assets. Since then, he has taken on roles of increasing responsibility. Earlier in his career, he held leadership roles at an international energy company, working in western Canada and western Europe. Mr. Groundwater is a professional engineer with APEGA, and he holds a Bachelor of Engineering degree in Chemical Engineering from the University of Calgary.

### *Tejay D. Haugen, P.L. (Eng.), P. Tech (Eng.)*

VICE PRESIDENT, OPERATIONS PLANNING

Mr. Haugen is the Vice President, Operations Planning of ARC Resources. In his role, Mr. Haugen is responsible for the Company's long-term production and infrastructure planning, facilities design, water and emissions management, and planning of our capital program. With more than 16 years experience in the energy industry, he has extensive technical and commercial knowledge of both production and operations. Most recently, he served as Manager, Operations Planning where he led planning, scheduling, and procurement for ARC's capital and production operations. Mr. Haugen joined ARC in 2006, holding several progressively senior roles within the operations and capital planning functions. Mr. Haugen is a Professional Licensee (Eng) with APEGA, and a Professional Technologist (Eng) with the ASET. He has a diploma in Petroleum Engineering Technology from the Southern Alberta Institute of Technology.

### *Sean W. Stuart, B.A.Sc, P.Eng*

VICE PRESIDENT, CAPITAL OPERATIONS

Mr. Stuart is the Vice President, Capital Operations of ARC Resources and is responsible for drilling, completions, and civil construction teams. With more than 20 years' experience in the energy industry, he has extensive knowledge of all technical aspects of subsurface development and well operations. Most recently, he served as Manager, Completions overseeing assets in Alberta and British Columbia. Mr. Stuart joined ARC in 2014, holding several leadership roles with increasing responsibility within the operations function. Before joining ARC, he worked at an intermediate energy company as a Team Lead for drilling, completions, and well servicing. Mr. Stuart is a professional engineer with APEGA and EGBC, and he has a Bachelor of Applied Science in Civil Engineering from the University of Waterloo.

### *Grant A. Zawalsky, B. Comm, LL.B*

CORPORATE SECRETARY

Mr. Zawalsky acts as Corporate Secretary for ARC Resources. He is a Vice Chair and Partner at the law firm of Burnet, Duckworth & Palmer LLP, and has more than 30 years of experience in securities and corporate law including securities offerings, mergers and acquisitions, and corporate governance. Mr. Zawalsky acts a director for several public and private energy companies including NuVista Energy Ltd., PrairieSky Royalty Ltd., and Whitecap Resources Ltd.

# AUDIT COMMITTEE DISCLOSURES

National Instrument 52-110 *Audit Committees* ("NI 52-110") has mandated certain disclosures for inclusion in this Annual Information Form. The text of the Audit Committee's mandate is attached as Appendix C to this Annual Information Form.

## Members of the Audit Committee

As of March 9, 2023, the members of the Audit Committee are Leontine van Leeuwen-Atkins (Chair), Farhad Ahrabi, and Carol Banducci; each is independent and financially literate within the meaning of NI 52-110.

The following comprises a brief summary of each member's education and experience:

### *Leontine van Leeuwen-Atkins*

Ms. Atkins has more than 30 years of international experience working across the energy value chain with expertise in business strategy, mergers and acquisitions, finance, and sustainability. Currently, she serves on the boards of Cameco Corporation and EPCOR Utilities Inc. From 2006 to 2019, she was a partner with KPMG LLP. During her tenure, she led the European Energy & Natural Resources practice, the Netherlands' Industrial Markets practice and Europe's Chemical and Pharmaceutical practice, focusing on strategic investments and initiatives. Ms. Atkins also served on KPMG Canada's National Board of Directors and, most recently, was Audit Committee Chair for Points International (sold in 2022 to LeCaisse/Plusgrade) and Seven Generations. Ms. Atkins is a past member of the executive committee and a current member of the mentoring committee of the Calgary Chapter of the Institute of Corporate Directors. She holds a Bachelor of Business Administration in Finance from Acadia University, and a Master of Business Administration from Dalhousie University. Ms. Atkins holds CPA and CA designations, as well as the ICD.D designation from the Institute of Corporate Directors. Ms. Atkins was awarded the FCPA/FCA in 2022 by the Canadian Institute of Chartered Accountants.

### *Farhad Ahrabi*

Mr. Ahrabi has more than 35 years of experience in international energy operations having worked in three different continents with extensive expertise in LNG and upstream crude oil and natural gas operations. His knowledge extends to joint venture management and operational excellence in global upstream and midstream operations. Mr. Ahrabi retired from Cameron LNG LLC where he spent seven and a half years as Chief Executive Officer in February 2022. In April 2022, Mr. Ahrabi joined Commonwealth LNG as President and Chief Executive Officer. Previously, Mr. Ahrabi spent 29 years with the BG Group (now part of Shell plc) where he held several executive positions. During his tenure with BG Group, within Canada, Mr. Ahrabi spent three years assessing LNG opportunities in British Columbia. Mr. Ahrabi holds a Bachelor of Science Degree in Chemical Engineering from the University of Wales, and a Doctorate Degree in Chemical Engineering with a focus on Enhanced Oil Recovery from the University of Exeter in the United Kingdom. He is a Chartered (Professional) Engineer and a member of the Institution of Chemical Engineers.

### *Carol T. Banducci*

Ms. Banducci has more than 30 years of international experience with a focus in operational, corporate, and senior leadership roles. She has extensive expertise in strategy development and implementation, finance and accounting. Most recently, Ms. Banducci was Executive Vice President and Chief Financial Officer of IAMGOLD Corporation. She also served as Chair of Niobec Inc. Previously, she was a senior leader with a major plastics and polymer producer and was Chief Financial Officer of Orica Explosives North America and ICI Explosives Canada & Latin America. Ms. Banducci serves as a Director with Hudbay Minerals Inc and Citibank Canada. She is a member of the Institute of Corporate Directors and is a past member of the Canadian Board Diversity Council. Ms. Banducci holds a Bachelor of Commerce from the University of Toronto.

## Principal Accountant Fees and Services

The Audit Committee has policies and procedures for the engagement of non-audit services and pre-approves each engagement or type of engagement in accordance with such policy.

PricewaterhouseCoopers LLP acted as ARC's external auditor for the fiscal years ended December 31, 2022 and 2021. The following is a summary of the external audit and non-audit services fees by category.

| Summary of External Audit and Non-audit Service Fees | | 2022 | | 2021 |
|---|---|---|---|---|
| Audit Fees | $ | 1,239,060 | $ | 1,166,300 |
| Audit Related Fees (1) | $ | — | $ | 26,750 |
| All Other Fees (2) | $ | 49,638 | $ | 252,150 |

1) The aggregate fees billed by our external auditor for assurance and related services that are reasonably related to the performance of the audit or review of the financial statements but which are not included in audit services fees.
2) Includes the assessment fee billed by the Canadian Public Accountability Board (the "CPAB") per the National Instrument 52-108 *Auditor Oversight* mandate for reporting issuers to have an audit completed by a CPAB participant firm, fees related to valuation services of restricted share awards, fees for services related to the Joint Management Information Circular relating to the Business Combination, fees for services related to the Business Acquisition Report, fees for services related to an IT Cybersecurity Assessment, and fees for services related to an End User Computing model.

# CONFLICTS OF INTEREST

During the year ended December 31, 2022, ARC did not have any existing or potential material conflicts of interest between the Company or a subsidiary of the Company and any director or officer of the Company or of a subsidiary of the Company.

# LEGAL PROCEEDINGS

In May 2018, ARC entered into a purchase and sale agreement with ACCEL Canada Holdings Limited ("ACCEL") to dispose of its interests in certain non-core assets located within the area of Redwater, Alberta for net proceeds of $130.3 million before post-closing adjustments. ARC had recognized in its accounts receivable at December 31, 2018, amounts owing from ACCEL in relation to post-closing adjustments and cash payments made by ARC on behalf of ACCEL after closing of the transaction and while ARC continued to act as operator of the disposed assets.

On May 31, 2019, ARC initiated a lawsuit against ACCEL for approximately $12 million for failure to pay certain of these amounts. On October 23, 2019, ACCEL filed a counterclaim in the Judicial District of Calgary of the Court of Queen's Bench of Alberta against ARC for $200 million for damages alleging breaches of contract or misrepresentation related to the transaction. On January 3, 2020, ARC filed its defence to the counterclaim. ARC's claims against ACCEL are currently stayed, though if ACCEL or its receiver, PricewaterhouseCoopers Inc., LIT, elects to advance the counterclaim against ARC, ARC expects to apply to lift the stay to prosecute its claim against ACCEL. Neither ACCEL nor the receiver has, at present, indicated an intention to pursue the counterclaim and Management believes they are unlikely to do so given the circumstances. Management does not expect the outcome of the counterclaim to result in a material outflow of resources by ARC.

On December 9, 2020, Steelhead LNG Ltd. and Steelhead Limited Partnership (collectively "Steelhead") filed a Statement of Claim in the Federal Court of Canada against Seven Generations Energy Ltd., Rockies LNG Limited Partnership, Rockies LNG GP Corp., and Birchcliff Energy Ltd. (collectively the "Defendants") alleging infringement of Steelhead's patent related to a floating near-shore LNG facility and seeking damages in excess of $250 million. ARC replaced Seven Generations as a defendant in the proceedings as a result of the Business Combination. On June 7, 2021, the Defendants filed their Statement of Defence and Counterclaim against Steelhead, Azimuth Capital Management IV Ltd., Azimuth Energy Partners IV (NR) LP and Azimuth Energy Partners IV LP. The Defendants brought a motion for summary trial related to Steelhead's infringement allegations, which was heard in June 2022. The decision from the summary trial was released on July 6, 2022, where the Court granted the motion for summary trial and found that the Defendants had not infringed Steelhead's patent. Steelhead has subsequently appealed the decision. A trial of the Defendants' counterclaims will be heard in September 2023. ARC does not expect the outcome of the claim or counterclaims to result in a material outflow of resources by ARC.

# INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as described in our Annual Information Form dated March 10, 2022, there is no material interest, direct or indirect, of any Director or Executive Officer, or to our knowledge any person or company that beneficially owns, or who exercises control or direction over, directly or indirectly, more than 10 per cent of outstanding common shares, or any associate or affiliate of any of the foregoing, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to affect the Corporation.

# DIVIDENDS

## Dividend Policy

The Board of Directors of ARC Resources has established a dividend policy of paying a quarterly dividend to holders of common shares on or about the 15th day of the month following the end of each quarter.

It is expected that the dividends declared and paid will be “eligible dividends” for the purposes of the Tax Act, and thus qualify for the enhanced gross-up and tax credit regime available to certain holders of common shares. However, no assurances can be given that all dividends will be designated as “eligible dividends” or qualify as “eligible dividends”.

Notwithstanding the foregoing, the amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors of ARC Resources and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditures, debt service requirements, operating expense, royalty burdens, foreign exchange rates, and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends.

In certain circumstances, the payment of dividends may be restricted by our borrowing agreements. For more information see “*Other Information Relating to Our Business - Borrowing.*”

## Dividend History

The following dividends were declared per common share in the last three completed financial years of ARC:

| **Dividends** | **2022** | **2021** | **2020** |
|---|---|---|---|
| January | — | — | $0.05 |
| February | — | — | $0.05 |
| March | $0.10 | $0.06 | $0.02 |
| April | — | — | — |
| May | — | — | — |
| June | $0.12 | $0.06 | $0.06 |
| July | — | — | — |
| August | — | — | — |
| September | $0.12 | $0.066 | $0.06 |
| October | — | — | — |
| November | — | — | — |
| December | $0.15 | $0.10 | $0.06 |
| **Total** | **$0.49** | **$0.286** | **$0.30** |

# MARKET FOR SECURITIES

The common shares commenced trading on the TSX on January 6, 2011 following the completion of the Trust Conversion. The trading symbol for the common shares is ARX.

The following table sets forth the high and low closing prices and the aggregate volume of trading in 2022 of the common shares on the TSX for the periods indicated (as quoted by Bloomberg).

| Toronto Stock Exchange | High ($) | Low ($) | Volume |
|---|---|---|---|
| January | 14.89 | 11.88 | 74,521,700 |
| February | 15.67 | 14.22 | 67,898,332 |
| March | 17.48 | 14.62 | 119,468,223 |
| April | 19.08 | 16.74 | 77,211,990 |
| May | 19.56 | 15.73 | 157,009,319 |
| June | 22.14 | 14.81 | 118,893,769 |
| July | 17.96 | 14.20 | 69,416,404 |
| August | 18.83 | 16.59 | 62,302,119 |
| September | 19.39 | 15.54 | 62,824,385 |
| October | 19.18 | 17.37 | 50,795,527 |
| November | 19.98 | 18.04 | 57,097,440 |
| December | 19.82 | 17.40 | 58,746,314 |

# INDUSTRY CONDITIONS

Companies operating in the Canadian crude oil and natural gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government, as well as with respect to the pricing and taxation of crude oil and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Canadian crude oil and natural gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments governments may enact in the future.

ARC currently holds interests in crude oil and natural gas properties, along with related assets in the Canadian provinces of Alberta and British Columbia. ARC's assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of ARC's 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 and construction of related infrastructure; (ii) technical drilling and well requirements; (iii) permitted locations and access to operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts, including by reducing emissions; (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 some of the principal aspects of the legislation, regulations, agreements, orders, directives, and a summary of other pertinent conditions that impact the crude oil and natural gas industry in western Canada. While these matters do not affect ARC's 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 matters carefully.

## Pricing and Marketing in Canada

### Crude Oil

Crude oil producers are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on crude oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply/demand balance, and contractual terms of sale.

Global crude oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In 2022, crude oil prices rose to the highest levels since 2014 due to tight supply and a resurgence in demand. The International Energy Agency forecasts robust growth in world crude oil demand in 2023, spurred by the relaxation of China's zero-COVID policy, despite newly emerging COVID-19 variants, interest rate increases in major economies, and other uncertainties with respect to the world economy.

In February 2022, Russian military forces invaded Ukraine. Ongoing military conflict between Russia and Ukraine has significantly impacted the supply of crude oil and natural gas from the region. In addition, many countries including Canada and the United States have imposed strict financial and trade sanctions against Russia, which sanctions may have far-reaching effects on the global economy in addition to the near-term effects on Russia. The long-term impacts of the conflict remain uncertain.

### Natural Gas

Negotiations between buyers and sellers determine 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, weather conditions, supply/demand balance, and other contractual terms of sale.

### 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, access to downstream transportation, length of contract term, supply/demand balance, and other contractual terms of sale.

## Exports from Canada

The Canada Energy Regulator (the "CER") regulates the export of crude oil, natural gas, and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the Canadian Energy Regulator Act (the "CERA"). Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government.

## Transportation Constraints and Market Access

### Oil Pipelines

Under Canadian constitutional law, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. Additional considerations may include provincial and municipal government requirements, legal opposition related to issues such as Indigenous rights and title, the government's duty to consult Indigenous Peoples, and the sufficiency of all relevant environmental review processes.

### Natural Gas and Liquefied Natural Gas

Natural gas prices in western Canada have been volatile in recent years due to increasing North American supply, limited access to markets, and limited storage capacity. Required repairs or upgrades to existing pipeline systems in western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. Companies that secure firm access to infrastructure 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 is generally lower than the prices received in other North American regions.

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition, and changing market conditions have resulted in the cancellation or delay of many of these projects.

## International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement ("CETA"), the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the United States Mexico Canada Agreement (the "USMCA"), which replaced the former North American Free Trade Agreement ("NAFTA") on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas, and NGLs from Canada, the implementation of the USMCA could impact western Canada's crude oil and natural gas industry as a whole, including ARC’s business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia, and Europe.

Canada is also party to the CETA, which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Following the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada entered into the Canada-United Kingdom Trade Continuity Agreement ("CUKTCA"), which replicates CETA on a bilateral basis to maintain the status quo of the Canada-United Kingdom trade relationship.

While it is uncertain what effect CETA, CUKTCA or any other trade agreements will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

# Land Tenure

## Mineral Rights

In Alberta and British Columbia, the provincial governments own most of the mineral rights to the crude oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licences, and permits (collectively, "leases") for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in western Canada conduct regular land sales where energy companies bid for the leases necessary to explore for and produce crude oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

All 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 disposition. In addition, Alberta has 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. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which they can demonstrate the presence of crude oil or natural gas, with the remainder reverting to the Crown.

# Royalties

## Crown Royalties

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. The royalty regime in a given province is in addition to applicable federal and provincial taxes and 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 negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable.

Producers and working interest owners of crude oil and natural gas rights may create additional royalties or royalty-like interests, such as overriding royalties, net profits interests and net carried interests, through private transactions, the terms of which are subject to negotiation.

The following is a description of key royalty programs that are applicable to ARC in the jurisdictions in which we operate. This is not meant to be a complete description of all royalty programs; please refer to the respective provincial websites for full royalty details.

### Alberta

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "MRF"). The MRF took effect on January 1, 2017. Wells drilled prior to January 1, 2017 continue to be governed by the prior "Alberta Royalty Framework" (the "ARF") for a period of 10 years, until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed five per cent royalty applies until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length, and historical costs). The new royalty rate will be payable on gross revenue generated from all production streams (crude oil, natural gas, and NGLs), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, the royalty rate will move to a sliding scale (based on volume and price) with a minimum gross royalty rate of five per cent. The downward adjustment of the royalty rate in the mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

<table>
<tr><th colspan="5">Alberta Royalty Regimes Summary</th></tr>
<tr><th>Royalty Regime</th><th>Product</th><th>Pre-payout</th><th>Post-payout or Mid-Life (MRF)</th><th>Mature Phase (MRF)</th></tr>
<tr><td rowspan="3">ARF - Royalty formulas based on price and production</td><td>Crude Oil</td><td rowspan="3">5%</td><td colspan="2">0% to 40%</td></tr>
<tr><td>Natural Gas</td><td colspan="2">5% to 36%</td></tr>
<tr><td>Liquids - C3 & C4 / C5+</td><td colspan="2">Flat 30% / Flat 40%</td></tr>
<tr><td rowspan="3">MRF - Royalty formulas based on price with a reduction for lower production during the mature phase</td><td>Crude Oil / Condensate / C5+</td><td rowspan="3">Pre-payout 5%</td><td>10% to 40%</td><td rowspan="3">Minimum 5%</td></tr>
<tr><td>Natural Gas</td><td>5% to 36%</td></tr>
<tr><td>C3 /C4</td><td>10% to 36%</td></tr>
</table>

### British Columbia

On October 7, 2021, the Government of British Columbia launched a comprehensive review of its oil and gas royalty system. The new oil and gas royalty system (the "New Framework") was announced in May 2022. The New Framework increases the minimum royalty rate from three per cent to five per cent, and eliminates the Deep Well, Marginal Well, Ultra-marginal Well, Low Productivity Well Rate Reduction, and Clean Growth Infrastructure royalty programs (the "Old Royalty Programs"). New wells drilled under the New Framework will pay the flat royalty of five per cent until capital spent on drilling and completions is recovered, at which point they will move to a price-sensitive royalty rate between five per cent and 40 per cent, depending on the specific commodity being produced.

Wells drilled on or after September 1, 2022 are not eligible to qualify for the Old Royalty Programs, and will pay a five per cent royalty rate for the equivalent of the first 12 months of production. Following this period, these wells will pay the prevailing price-sensitive royalty rates until September 1, 2024 when all wells will be transitioned to the New Framework. Wells drilled prior to September 1, 2022 will pay royalties based on the current framework until September 1, 2024, at which time those wells will be transitioned to the New Framework and will no longer be able to take advantage of the Old Royalty Programs.

Under the current system, the royalty payable on crude oil produced on Crown lands depends on the type and vintage of the crude oil, the quantity of crude oil produced in a month, the value of that crude oil, and any applicable royalty exemptions. ARC's crude oil wells qualify for the lowest vintage royalty rates available reflecting the higher unit costs of both exploration and extraction.

The royalty payable on natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For natural gas wells, the royalty rate depends on the date of acquisition of the tenure rights and the spud date of the well. The royalties payable on NGLs produced on Crown lands are levied at a flat rate of 20 per cent of the sales volume.

| British Columbia Royalty Regimes Summary | | | |
|---|---|---|---|
| **Product** | **Crude Oil Wells** | **Gas Wells - Pre-payout** | **Gas Wells - Post-payout** |
| **Crude Oil** - based on oil production | 0% to 23% | N/A | N/A |
| **Natural Gas** - based on price | 8% to 13% | 3% to 6% | 9% to 27% |
| **Condensate** | 20% | 3% to 6% | 20% |
| **Liquids** - C2-C5 | 20% | 3% to 6% | 20% |

## Regulatory Authorities and Environmental Regulation

### General

The western Canadian crude oil and natural gas industry is 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 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 environmental legislation, including legislation related to air pollution and greenhouse gas ("GHG") emissions (typically measured in terms of their global warming potential and expressed in terms of carbon dioxide equivalent ("$CO_2e$"), may impose further requirements on operators and other companies in the crude oil and natural gas industry.

## Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

The CERA and the *Impact Assessment Act* (the "IAA") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure, and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction, and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the Impact Assessment Agency (the "IA Agency") or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the crude oil and natural gas industry include pipelines that require more than 75 kilometres of new rights of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps, and certain refining, processing, and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority 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.

In May 2022, the Alberta Court of Appeal released its decision in response to the Government of Alberta's submission of a reference question regarding the constitutionality of the IAA. The Court found the IAA to be unconstitutional in its entirety, stating that the legislation effectively granted the federal government a veto over projects that were wholly within provincial jurisdiction. Shortly after the decision was released, the Government of Canada announced its intention to appeal the decision to the Supreme Court of Canada.

## Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related statutes including the *Oil and Gas Conservation Act* (the "OGCA"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement 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 Land and Property Rights Tribunal, as well as the Alberta Ministry of Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its 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. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Parks, the Alberta Ministry of Energy, the Aboriginal Consultation Office, and the Land Use Secretariat.

The Government of Alberta's land-use policy 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.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, induced seismicity related to industry activity such as hydraulic fracturing and waste water disposal. 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 whereas waste water disposal involves the disposal of produced water into subsurface formations that are void of producible hydrocarbons or fresh water. In recent years, both activities have been linked to increased seismicity in the areas where they take place, prompting regulatory authorities to investigate these activities further.

The AER has developed monitoring and reporting requirements that apply to all crude oil and natural gas producers working in areas where the likelihood of seismicity related to hydraulic fracturing is higher, and implemented the requirements in *Subsurface Order Nos. 2, 6,* and *7*. The regions with these protocols in place are Fox Creek, Red Deer, and Brazeau. ARC does not have operations in Fox Creek, Red Deer, or Brazeau. Currently, there are no Subsurface Orders related to water disposal.

### British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "OGAA") regulates conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the BCER has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives and requires the BCER to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and permits, licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

In November 2022, the Government of British Columbia passed the *Energy Statutes Amendment Act, 2022* (the "ESA Act"), changing the name of the British Columbia Oil and Gas Commission to the British Columbia Energy Regulator and expanding its mandate to include oversight of hydrogen, ammonia, and methanol. In support of the government's stated desire to transition away from fossil fuels and grow the province's hydrogen industry, the OGAA will also be renamed the *Energy Resources Activities Act* (the "ERAA"). In addition to expanding the BCER's jurisdiction to include hydrogen, ammonia, and methanol, the updated ERAA will also expand director and officer responsibility for costs associated with orphan sites.

An updated *Environmental Assessment Act* came into force in December 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasises early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building. Simultaneously with the enactment of the *Environmental Assessment Act*, the Government of British Columbia enacted the accompanying *Reviewable Projects Regulation*, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation, and other GHG intensive projects. In conducting an environmental assessment, the British Columbia Environmental Assessment Office will consider the environmental, health, cultural, social, and economic effects of a proposed project.

## Hydraulic Fracturing

Hydraulic fracturing is an important and common practice to stimulate production of crude oil and natural gas from dense subsurface rock formations. The process 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. ARC routinely conducts hydraulic fracturing in its completions activities. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

### Alberta

Minor earthquakes are common in certain parts of Alberta, and are generally clustered around the municipalities of Cardston, Fox Creek, Rocky Mountain House, Brazeau, and Red Deer. ARC does not have any operations in these areas. ARC experiences induced seismicity associated with wastewater disposal at its Kakwa property. ARC proactively monitors seismicity using seismometers, regulations, and industry best practices aimed at mitigating or minimizing any effects of induced seismicity. In addition, the Company works collaboratively with industry peers in the region to coordinate activities and reduce risks associated with seismic activity. The AER continues to monitor seismic activity around the province and may extend its monitoring and reporting requirements as they relate to seismic events to other areas of the province if necessary. The implementation of new regulations or modification of existing regulations may adversely affect ARC's business operation, financial condition, results of operations, and prospects.

### British Columbia

In 2018, the Government of British Columbia commissioned an independent scientific review panel to analyze hydraulic fracturing in the province and determine, among other things, how British Columbia's regulatory framework can be improved to better manage safety and environmental risks resulting from hydraulic fracturing operations. The study resulted in approximately 100 action points for the government to address around water management and handling, engagement, and seismicity. At this time there has been no regulatory impact resulting from the study; however, the government continues to work with the BCER and area operators. The implementation of new regulations or modification of existing regulations, in response to the panel's findings, may adversely affect ARC's business operation, financial condition, results of operations, and prospects.

Due to seismic activity recorded in the Kiskatinaw Seismic Monitoring and Mitigation Area (the "KSMMA"), the BCER issued special notification and monitoring requirements in May 2018 for hydraulic fracturing operators in the KSMMA. These requirements include, among others, the submission of a seismic monitoring and mitigation plan prior to conducting operations, pre-operation notification to both residents and the BCER, and the suspension of fracturing activities if a seismic event above a 3.0 magnitude occurs. On November 29, 2018, hydraulic fracturing operations of a natural gas producer in the Montney area in British Columbia were suspended after a series of three seismic events, ranging from 3.4 to 4.5 in magnitude which the BCER attributed to hydraulic fracturing. The BCER allowed the natural gas producer to resume operations in the Montney on October 21, 2019, but their suspension demonstrates the BCER's willingness to enforce its enhanced regulatory requirements. The same natural gas producer was also suspended from using a wastewater disposal well in 2019 due to seismicity attributed to the use of that well, demonstrating that the BCER's monitoring and oversight of seismic risk is not limited to hydraulic fracturing. In April 2021, the BCER introduced enhancements to the special notification and monitoring requirements for hydraulic fracturing operators in the KSMMA, expanding the boundaries of the requirements. Under the enhanced requirements, a magnitude 3.0 or above seismic event will result in the immediate suspension of fracturing activities from the suspected well(s) for a minimum of five calendar days. The BCER is working closely with area operators, continues to monitor seismic events within areas of active crude oil and natural gas operations, and may implement similar requirements in other areas, if necessary. See the section entitled *"Industry Conditions - Regulatory Authorities and Environmental Regulation - British Columbia'*.

The Government of British Columbia has come under increased scrutiny for its enforcement of environmental assessment, safety and licensing requirements for water storage reservoirs, referred to as dams, which are constructed to provide water required for hydraulic fracturing operations. Under the *Water Sustainability Act*, the storage of water from a groundwater source or a stream requires authorization. In addition, structures constructed for water storage above natural grade elevation behind a berm or barrier (i.e., "live storage") are considered dams that require compliance under the Dam Safety Regulations and with the construction and operations standards specified by the Ministry of Forests, Lands and Natural Resources Operations. Despite these regulatory requirements, reports have surfaced indicating that a number of unlicensed dams throughout northeastern British Columbia have been constructed without the required regulatory authorization. While the BCER has issued compliance orders with respect to individual dams, it is uncertain how, and to what extent the relevant industry regulators will respond to this issue. All water storage reservoirs constructed by ARC meet the necessary regulatory approvals and are in full compliance with the above-mentioned regulations. The Corporation has taken additional steps to ensure all third-party water storage reservoirs used to support ARC's hydraulic fracturing operations are in compliance.

## Liability Management

The provinces of Alberta and British Columbia have each implemented similar liability management programs in respect to upstream crude oil and natural gas wells, facilities, and pipelines. These programs are designed to assess a licensee's ability to address its suspension, abandonment, remediation, and reclamation liabilities. A licensee whose deemed liabilities exceed its deemed assets within the jurisdiction is required to provide a security deposit.

### Alberta

The AER administers the Liability Management Framework (the "AB LM Framework") and the Liability Management Rating Program (the "AB LMR Program") to manage liability for most conventional upstream crude oil and natural gas wells, facilities, and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AB LM Framework. This change was effected under key new AER directives in 2021, and further updates released in 2022.

Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the AB LM Framework include a new Licensee Capability Assessment System (the "AB LCA"), a new Inventory Reduction Program (the "AB IR Program"), and a new Licensee Management Program ("AB LM Program"). Meanwhile, some programs under the AB LMR Program remain in effect, including the Oilfield Waste Liability Program (the "AB OWL Program"), the Large Facility Liability Management Program (the "AB LF Program") and elements of the Licensee Liability Rating Program (the "AB LLR Program"). The mix between active programs under the AB LM Framework and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

Complementing the AB LM Framework and the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "Orphan Fund") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and the AB OWL Program, including ARC, fund the Orphan Fund through a levy administered by the AER. However, given the increase in orphaned crude oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment and reclamation work. A separate orphan levy applies to persons holding licences subject to the AB LF Program. Collectively, these programs are 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.

The Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "Redwater" decision), provides the backdrop for Alberta's approach to liability management. As a result of 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 licence transfer when any such 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. In April 2020, the Government of Alberta passed the *Liabilities Management Statutes Amendment Act*, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. These changes came into force in June 2020.

One important step in the shift to the AB LM Framework has been amendments to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("Directive 067"), which deals with licensee eligibility to operate wells and facilities. All licence transfers and the granting of new well, facility, and pipeline licences in Alberta are subject to AER approval. Previously under the AB LMR Program, as a condition of transferring existing AER licences, approvals, and permits, all transfers required transferees to demonstrate that they had a liability management rating of 2.0 or higher immediately following the transfer. If transferees did not have the required rating, they would have to otherwise prove to the satisfaction of the AER that they could meet their abandonment and reclamation obligations, through means such as posting security or reducing their existing obligations. However, amendments from April 2021 to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

Alongside changes to Directive 067, the AER introduced *Directive 088: Licensee Life-Cycle Management* ("Directive 088") in December 2021 under the AB LM Framework. Directive 088 replaces, to an extent, the AB LLR Program with the AB LCA. Whereas the AB LLR Program previously assessed a licensee based on a liability rating determined by the ratio of a licensee's deemed asset value relative to the deemed liability value of its crude oil and natural gas wells and facilities, the AB LCA now considers a wider variety of factors and is intended to be a more comprehensive assessment of corporate health. Such factors are wide reaching and include: (i) a licensee's financial health; (ii) its established total magnitude of liabilities, (iii) the remaining lifespan of its mineral resources and infrastructure; (iv) the management of its operations; (v) the rate of closure activities and spending, and pace of inactive liability growth; and (vi) and its compliance with administrative and regulatory requirements. These various factors feed into a broader holistic assessment of a licensee under the AB LM Framework. In turn, that holistic assessment provides the basis for assessing risk posed by licence transfers, as well as any security deposit that the AER may require from a licensee in the event that the regulator deems a licensee at risk of not being able to meet its liability obligations. However, the liability management rating under the LLR Program is still in effect for other liability management programs such as the AB OWL Program and the AB LF Program, and will remain in effect until a broadened scope of Directive 088 is phased in over time.

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry-wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target. The AER has also indicated that it will implement a closure nomination program (the "CN Program") in 2023. Under the program, those who qualify may nominate certain crude oil and natural gas sites for closure. Details regarding the CN Program and the mechanism through which nominated sites will be abandoned and reclaimed are forthcoming.

The Government of Alberta followed the announcement of the AB LM Framework with amendments to the Oil and Gas Conservation Rules and the Pipeline Rules in late 2020. The changes to these rules fall into three principal categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation, and reclamation of inactive or marginal crude oil and natural gas infrastructure. In 2018, for example, the AER announced a voluntary area-based closure ("ABC") program. The ABC program is designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Parties seeking to participate in the program must commit to an inactive liability reduction target to be met through closure work performed on inactive assets. ARC currently participates in the ABC program and continues to allocate funds to abandonment and reclamation operations and is in compliance with all requirements.

## British Columbia

Similar to Alberta, the BCER has moved away from the formulaic approach to liability management set out in the Liability Management Rating Program, towards a more holistic assessment of a permit holder's ability to meet its abandonment and reclamation obligations. The BCER implemented the Permittee Capability Assessment (the "BC PCA") on April 1, 2022. Under the BC PCA, the financial risk of a permit holder is assessed based on its: (i) assets to liabilities ratio; (ii) net profit margin (three-year average); (iii) interest coverage ratio; (iv) cash flow to debt ratio; and (v) debt to equity ratio. A permit holder is assessed on these factors based on the financial information it is required to submit to the BCER intermittently throughout the year. The permit holder is then evaluated on the magnitude of its liabilities, based on the deemed abandonment, assessment, remediation, and reclamation liability associated with the permit holder's dormant, inactive, and marginal sites. If the BCER deems a permit holder to be high-risk under the BC PCA based on its financial risk and the magnitude of its liabilities, the regulator may require that permit holder to engage in corrective action. Corrective action could include the submission of security deposits and/or the completion of liability reduction work. Regarding the latter, the BCER will attempt to engage with permit holders to develop corrective action plans prior to issuing corrective action requirements.

In the spring of 2019, a liability-based levy paid to the *Orphan Site Reclamation Fund* ("OSRF") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The OGAA permits the BCER to impose more than one levy in a given calendar year.

The *Dormancy and Shutdown Regulation* (the "Dormancy Regulation") establishes the first set of legally imposed timelines for the restoration of crude oil and natural gas wells in western Canada. The Dormancy Regulation classifies different sites based on activity levels associated with each site, with a goal of ensuring that 100 per cent of currently dormant sites are reclaimed by 2036 with additional regulated timelines for sites that become dormant between 2019 and 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation, and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BCER, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within

60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan.

The Government of British Columbia passed amendments to the *Oil and Gas Activities Act* under the *Miscellaneous Statutes Amendment Act (No.2)* in October 2021. These amendments allow the BCER to grant exemptions for strict compliance with the requirements of the Dormancy Regulation. In turn, this may mean that a permit holder can, with approval, depart from the regulated timelines set under the Dormancy Regulation. The relevant amendments which provide the BCER with the power to grant these exemptions came into force on October 28, 2021.

# Climate Change Regulation

Climate change regulation at each of the international, federal, and provincial levels has the potential to significantly affect the future of the crude oil and natural gas industry in Canada. These impacts are uncertain and it is not possible to predict what future policies, laws, and regulations will entail. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on ARC’s operations and cash flow.

## Federal

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. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing 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. In 2016, Canada committed to reducing its emissions by 30 per cent below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40 to 45 per cent below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the crude oil and natural gas sector to 75 per cent of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the crude oil and natural gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

In line with the Prime Minister's pledge to impose a cap on emissions from the crude oil and natural gas sector, the federal government published a discussion paper on July 18, 2022 that outlines two potential regulatory options for such a cap. Those proposed options are either to: (i) implement a new cap-and-trade system that would set a limit on emissions from the sector; or (ii) modify the existing pollution pricing benchmark (as discussed below) to limit emissions from the sector. These options are currently under review and interested parties had the opportunity to make submissions regarding the proposed cap, ending in September 2022. The form of emissions cap on the crude oil and natural gas sector and the overall effect of such a cap remain uncertain.

The Government of Canada 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. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "GGPPA"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("OBPS") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on $CO_2e$ emissions. This system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by $10 per year until it reached a maximum price of $50 per tonne of $CO_2e$ in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022. Commencing in 2023, the benchmark price per tonne of $CO_2e$ will increase by $15 per year until it reaches $170 per tonne of $CO_2e$ in 2030. Effective January 1, 2023, the minimum price permissible under the GGPPA rose to $65 per tonne of $CO_2e$.

While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

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 the intentional venting of methane and ensure 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 crude oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by approximately 20 megatonnes by 2030.

The federal government has enacted the *Multi-Sector Air Pollutants Regulation* under the authority of the *Canadian Environmental Protection Act, 1999*, which regulates certain industrial facilities and equipment types, including boilers and heaters used in the upstream crude oil and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emissions by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut crude oil and natural gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emissions vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and Métis to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The *Canadian Net-Zero Emissions Accountability Act* (the "CNEAA") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions-reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and Crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the CNEAA is required every five years from the date the CNEAA came into force.

The Government of Canada introduced its *2030 Emissions Reduction Plan* (the "2030 ERP") on March 29, 2022. In the 2030 ERP, the Government of Canada proposes a roadmap for Canada's reduction of GHG emissions to 40 to 45 per cent below 2005 levels by 2030. As the first emissions reduction plan issued under the CNEAA, the 2030 ERP aims to reduce emissions by incentivizing electric vehicles and renewable electricity, and capping emissions from the crude oil and natural gas sector, among other measures.

On June 8, 2022 the Canadian Greenhouse Gas Offset Credit System Regulations were published in the Canada Gazette. The regulations establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS through Canada's Greenhouse Gas Offset Credit System. The system enables project proponents to generate federal offset credits through projects that reduce GHG emissions under a published federal GHG offset protocol. Offset credits can then be sold to those seeking to meet limits imposed under the OBPS or those seeking to meet voluntary targets.

On June 20, 2022, the Clean Fuel Regulations came into force, establishing Canada's Clean Fuel Standard. The Clean Fuel Standard will replace the former Renewable Fuels Regulation, and aims to discourage the use of fossil fuels by increasing the price of those fuels when compared to lower-carbon alternatives. Coming into force in 2023, the Clean Fuel Standard will impose obligations on primary suppliers of transportation fuels in Canada and require fuels to contain a minimum percentage of renewable fuel content and meet emissions caps calculated over the life cycle of the fuel. The Clean Fuel Regulations also establish a market for compliance credits. Compliance credits can be generated by primary suppliers, among others, through carbon capture and storage, producing or importing low-emissions fuel, or through end-use fuel switching (for example, operating an electric vehicle charging network).

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("CCUS") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. Beginning in 2022, the federal government plans to spend $319 million over seven years to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050.

## Alberta

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On January 1, 2023, the carbon tax payable in Alberta increased from $50 to $65 per tonne of $CO_2e$, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. In December 2019, the federal government approved Alberta's *Technology Innovation and Emissions Reduction* ("TIER") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020, and as amended on January 1, 2023, and replaced the previous *Carbon Competitiveness Incentives Regulation*. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the 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. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10 per cent as measured against that facility's individual benchmark, with a further two per cent reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports. Facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta aims to lower annual methane emissions by 45 per cent by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020, and in November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

## British Columbia

In August 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80 per cent below 2007 levels by 2050. British Columbia was also the first Canadian province to implement a revenue-neutral fuel charge. The fuel charge is currently set at $65 per tonne of $CO_2e$, and will continue to increase in line with the GGPPA minimum charge. Federal carbon pricing mechanisms are not currently in force in British Columbia, as the province's programs currently meet or exceed the federal benchmark stringency requirements.

In January 2016, the *Greenhouse Gas Industrial Reporting and Control Act* (the "GGIRCA") came into effect, which streamlined the regulatory process for large-emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

In December 2018, the Government of British Columbia announced an updated Clean Energy Plan, "CleanBC", which seeks to ensure that British Columbia achieves 75 per cent of its GHG emissions reduction target by 2030. The CleanBC plan includes a number of strategies targeting the industrial, transportation, construction, and waste sectors of the British Columbia economy. Key initiatives include: (i) increasing the generation of electricity from clean and renewable energy sources; (ii) imposing a 15 per cent renewable content requirement in natural gas by 2030; (iii) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20 per cent by 2030; (iv) investing in the electrification of crude oil and natural gas production; (v) reducing 45 per cent of methane emissions associated with natural gas production; and (vi) incentivizing the adoption of zero-emissions vehicles. Complementing its CleanBC plan, on March 26, 2021, the Government of British Columbia announced a number of sector-specific emissions reduction targets, established with reference to 2007 emissions levels, that it aims to achieve by 2030, including reduction targets of 27 to 32 per cent for the transportation sector, 38 to 43 per cent for industry, and 33 to 38 per cent for crude oil and natural gas.

The Government of British Columbia established the CleanBC Industry Fund in 2019 to support clean industry development in the province. The fund uses a portion of carbon tax revenue paid by large emitters to invest in projects aimed at reducing GHG emissions. In March 2021, the Government of British Columbia temporarily increased the provincial share of funding to up to 90 per cent of project costs with a cap of $25 million per project. In 2021, the CleanBC Industry Fund invested $83.5 million in 32 emissions performance projects across British Columbia.

In October 2021, the Government of British Columbia announced a more ambitious climate change plan called the CleanBC Roadmap to 2030 (the "CleanBC Roadmap"), aimed at helping British Columbia achieve its 2030 emission reduction targets established under the CleanBC plan. The CleanBC Roadmap includes plans for, among other things, laws requiring 90 per cent of new passenger vehicles sold in the province to be zero-emission by 2030, all new buildings to be zero-carbon beginning in 2030, the electrification of public transit and ferries, and for increased support for clean hydrogen and negative emissions technology. Further, the CleanBC Roadmap plans to increase carbon taxation in the province to meet or exceed the federal GGPPA benchmark.

In January 2020, the BCER implemented a series of amendments to the British Columbia *Drilling and Production Regulation* that will require facility and well permit holders to, among other things, reduce natural gas leaks and curb monthly natural gas emissions from their equipment and operations. In November 2020, the Government of Canada and the Government of British Columbia announced that they had finalized an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia.

## Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous Peoples 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 crude oil and natural gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("UNDRIP") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the crude oil and natural gas industry in western Canada. For example, in November 2019, the Declaration on the Rights of Indigenous Peoples Act ("DRIPA") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the United Nations Declaration on the Rights of Indigenous Peoples Act ("UNDRIP Act") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives. On June 21, 2022, the Minister of Justice and Attorney General issued the First Annual Progress Report on the implementation of the UNDRIP Act (the "Progress Report"). The Progress Report provides that, as of June 2022, the federal government has sought to implement the UNDRIP Act by, among other things, creating a Secretariat within the Department of Justice to support Indigenous participation in the implementation of UNDRIP, consulting with Indigenous Peoples to identify their priorities, drafting an action plan to align federal laws with UNDRIP, and implementing efforts to educate federal departments on UNDRIP's principles.

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 the DRIPA and UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian crude oil and natural gas industry. This applies specifically to their ability to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous Peoples collaborate in impact assessment moving forward, but has confirmed that the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act.

On June 29, 2021, the British Columbia Supreme Court issued a judgement in *Yahey v British Columbia* (the "Blueberry Decision"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nations ("BRFN") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. The Blueberry Decision may have significant impacts on the regulation of industrial activities in northeast British Columbia, and may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties, as has been seen in Alberta.

On January 18, 2023, the Government of British Columbia and the BRFN signed the Blueberry River First Nations Implementation Agreement (the "BRFN Agreement"). The BRFN Agreement aims to address cumulative effects of development on BRFN's claim area through restoration work, establishment of areas protected from industrial development, and a constraint on development activities. Such measures will remain in place while a long-term cumulative effects management regime is implemented. Specifically, the BRFN Agreement includes, among other measures, the establishment of a $200 million restoration fund by June 2025, an ecosystem-based management approach for future land-use planning in culturally important areas, limits on new crude oil and natural gas development, and a new planning regime for future crude oil and natural gas activities. The BRFN will receive $87.5 million over three years, with an opportunity for increased benefits based on crude oil and natural gas revenue-sharing and provincial royalty revenue-sharing in the next two fiscal years. The BRFN Agreement now serves as a blueprint for other agreements between the Government of British Columbia and First Nations in Treaty 8 territory. In late January 2023, the Government of British Columbia and four Treaty 8 First Nations - Fort Nelson, Salteau, Halfway River, and Doig River First Nations - reached consensus on a collaborative approach to land and resource planning (the “Consensus Agreement”). The Consensus Agreement implements various initiatives including a “cumulative effects” management system linked to natural resource landscape planning and restoration initiatives, new land-use plans and protection measures, and a new revenue-sharing approach to support the priorities of Treaty 8 First Nations communities.

In July 2022, Duncan's First Nation filed a lawsuit against the Government of Alberta relying on similar arguments to those advanced successfully by the BRFN. Duncan's First Nation claims in its lawsuit that Alberta has failed to uphold its treaty obligations by authorizing development without considering the cumulative impacts on the First Nation's treaty rights. The long-term impacts of the Blueberry Decision and the Duncan's First Nation lawsuit on the Canadian crude oil and natural gas industry remain uncertain.

## Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the "ESTMA") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction, and holding permits. All companies subject to ESTMA must report payments over $100,000 made to any level of a Canadian or foreign government (including Indigenous Peoples), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments, and other prescribed categories of payments.

# RISK FACTORS

A discussion of ARC's risk factors is contained in the section entitled "*Risk Factors*" in the MD&A, which section is incorporated by reference herein. Also see other documents filed by ARC from time to time available on SEDAR at www.sedar.com.

# TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for ARC's common shares is Computershare Trust Company of Canada at its principal offices in Calgary and Toronto.

# MATERIAL CONTRACTS

During the year ended December 31, 2022, ARC has not entered into any contracts, nor are there any contracts still in effect, that are material to ARC, other than contracts entered into in the ordinary course of business.

# INTEREST 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 statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent qualified reserves evaluator, and PricewaterhouseCoopers LLP, our independent external auditor for the year ended December 31, 2022. As at the date hereof the designated professionals of GLJ, as a group, beneficially owned, directly or indirectly, less than one per cent of our outstanding securities, including the securities of our associates and affiliates.

The Corporation's auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have prepared an independent auditor's report dated February 9, 2023, in respect of the Corporation's consolidated financial statements as at December 31, 2022 and December 31, 2021 and for the years then ended. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of Chartered Professional Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any Director or Officer of any of the aforementioned persons or companies, is or is expected to be elected, appointed, or employed as a Director or Officer, of ARC Resources or of any of our associate or affiliate entities. Grant A. Zawalsky, the Corporate Secretary of ARC Resources, is a partner of Burnet, Duckworth & Palmer LLP, which law firm renders legal services to ARC Resources.

# NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this document and in other materials disclosed by the Company, ARC employs certain measures to analyze its financial performance, financial position, and cash flow. These non-GAAP and other financial measures are not standardized financial measures under IFRS and may not be comparable to similar financial measures disclosed by other issuers.

## Capital Expenditures

The most directly comparable GAAP measure to capital expenditures is cash flow used in investing activities. The following table details the composition of capital expenditures and a reconciliation to its most directly comparable GAAP measure, cash flow used in investing activities.

| | Year Ended | | |
|---|---|---|---|
| **($ millions)** | **December 31, 2022** | **December 31, 2021** | **December 31, 2020** |
| Cash flow used in investing activities | **1,413.2** | **808.1** | **364.3** |
| Cash acquired upon close of Business Combination | — | 4.9 | — |
| Acquisition of crude oil and natural gas assets | (2.7) | (1.1) | (0.2) |
| Disposal of crude oil and natural gas assets | 11.9 | 79.7 | 1.8 |
| Long-term investments | (12.0) | (2.5) | — |
| Change in non-cash working capital | 15.7 | 164.7 | (30.6) |
| Other [1] | 15.8 | 8.0 | 7.9 |
| **Capital expenditures** | **1,441.9** | **1,061.8** | **343.2** |

(1) Comprises non-cash capitalized costs related to the Company's right-of-use asset depreciation and share-based compensation.

# ADDITIONAL INFORMATION

Additional information including remuneration and indebtedness of Directors and Officers of ARC Resources, principal holders of the common shares and options to purchase common shares, will be contained in the Information Circular - Proxy Statement of the Corporation which relates to the Annual Meeting of Shareholders. Additional financial information is provided in the financial statements and MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com. Other additional information relating to us may be found on SEDAR at www.sedar.com.

# APPENDIX A

# REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR FORM 51-101F2

To the Board of Directors of ARC Resources Ltd. (the “Company”):

1. We have evaluated the Company’s reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the reserves 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 data are free of material misstatement. An evaluation also includes assessing whether the reserves 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 plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 per cent, included in the reserves data of the Company evaluated for the year ended December 31, 2022, 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 (before income taxes, 10% discount rate - $MM) | | | |
|---|---|---|---|---|---|---|
| Independent Qualified Reserves Evaluator or Auditor | Effective Date of Evaluation Report | Location of Reserves (Country or Foreign Geographic Area) | Audited | Evaluated | Reviewed | Total |
| GLJ Ltd. | December 31, 2022 | Canada | — | 21,144 | — | **21,144** |

6. In our opinion, the reserves data, 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 data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

8. Because the reserves 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:

GLJ Ltd., Calgary, Alberta, Canada, February 8, 2023.

/s/ Chad P. Lemke

Chad P. Lemke, P. Eng.
Executive Vice President and COO

# APPENDIX B

# REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION FORM 51-101F3

Management of ARC Resources Ltd. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's crude oil and natural 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 and prospective resources data.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Safety, Reserves and Operational Excellence 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 with management and the independent qualified reserves evaluator.

The Safety, Reserves and Operational Excellence Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with crude oil and natural gas activities and has reviewed that information with Management. The Board of Directors has, on the recommendation of the Safety, Reserves and Operational Excellence Committee, approved

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

b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

c) the content and filing of this report.

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

/s/ Terry M. Anderson
Terry M. Anderson
President and Chief Executive Officer

/s/ Larissa M. Conrad
Larissa M. Conrad
Senior Vice President and Chief Development Officer

/s/ Michael G. McAllister
Michael G. McAllister
Director and Chair of the Safety, Reserves and Operational Excellence Committee

/s/ David R. Collyer
David R. Collyer
Director and Member of the Safety, Reserves and Operational Excellence Committee

March 9, 2023

# APPENDIX C

# MANDATE OF THE AUDIT COMMITTEE

## Mandate of the Audit Committee (February 9, 2023)

### Role and Objective

The Audit Committee (the “Committee”) is a committee of the Board of Directors of ARC Resources Ltd. (the “Corporation”) to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board of Director approval, the audited financial statements, and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to the Corporation and its subsidiaries, are as follows:

- To assist Directors to meet their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters.
- To provide better communication between Directors and external auditors.
- To ensure the external auditors' independence.
- To review Management’s implementation and maintenance of an effective system of internal control over financial reporting and disclosure control over financial reporting.
- To increase the credibility and objectivity of financial reports.
- To facilitate in-depth discussions between Directors on the Committee, Management and external auditors.

The primary responsibility for the financial reporting, information systems, risk management and internal and disclosure controls of the Corporation is vested in Management and overseen by the Board of Directors of the Corporation. At each meeting, the Committee may meet separately with Management and will meet in separate, closed sessions with the external auditors and then with the independent Directors in attendance.

### Mandate and Responsibilities of Committee

#### *Financial Reporting and Related Public Disclosure*

1. It is a primary responsibility of the Committee to review and recommend for approval to the Board of Directors the annual and quarterly financial statements of the Corporation. The Committee is also to review and recommend to the Board of Directors for approval the financial statements and related information included in prospectuses, Management Discussion and Analysis, financial news releases, Information Circular-Proxy Statements and Annual Information Forms. The process should include but not be limited to:

    a. reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

    b. reviewing significant management judgments and estimates that may be material to financial reporting including alternative treatments and their impacts;

    c. reviewing the presentation and impact of any significant risks and uncertainties that may be material to financial reporting including alternative treatments and their impacts;

    d. reviewing accounting treatment of significant, unusual, or non-recurring transactions;

    e. reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

    f. reviewing unresolved differences between Management and the external auditors;

    g. reviewing the Corporation’s public disclosure regarding non-GAAP and other financial measures;

h. reviewing the Corporation's disclosure contained in the financial statements or other financial reporting documents relating to environmental, social and governance;

i. determining through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed; and

j. reviewing all financial reporting relating to risk exposure including the identification, monitoring, and mitigation of business risk and its disclosure.

2. The Committee shall satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information from the Corporation's financial statements and periodically assess the adequacy of those procedures.

### *Internal Controls over Financial Reporting and Information Systems*

3. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to the Corporation's internal control over financial reporting and information systems. The process should include but not be limited to:

    a. inquiring as to the adequacy and effectiveness of the Corporation's system of internal controls over financial reporting and review Management's report on internal control of financial reporting;

    b. establishing procedures for the confidential, anonymous submission by employees of the Corporation of concerns relating to accounting, internal control over financial reporting, auditing or Code of Business Conduct and Ethics matters and periodically review a summary of complaints and their related resolution; and

    c. establishing procedures for the receipt, retention, and treatment of complaints received by the Corporation regarding accounting, internal accounting controls, or auditing matters.

### *Extractive Sector Transparency Measures Act*

4. It is the responsibility of the Committee to satisfy itself on behalf of the Board to review management's process for certification under the *Extractive Sector Transparency Measures Act* (Canada).

### *External Auditors*

5. With respect to the appointment of external auditors by the Board, the Committee shall:

    a. be directly responsible for overseeing the work of the external auditors engaged for the purpose of issuing an auditors' report or performing other audit, review, or attest services for the Corporation, including the resolution of disagreements between Management and the external auditor regarding financial reporting;

    b. review the terms of engagement of the external auditors, including the appropriateness and reasonableness of the auditors' fees;

    c. review and evaluate annually the external auditors' performance, and periodically, (at least every five years) conduct a comprehensive review of the external auditor;

    d. recommend to the Board appointment of external auditors and the compensation of the external auditors;

    e. when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;

    f. review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors in accordance with policies and procedures adopted by the Audit Committee from time to time;

    g. inquire as to the independence of the external auditors and obtain, at least annually, a formal written statement delineating all relationships between the external auditors and the Corporation as contemplated by Independence Standards Board No. 1;

h. review the Annual Report of the Canadian Public Accountability Board ("CPAB") concerning audit quality in Canada and discuss implications for the Corporation;

i. review any reports issued by CPAB regarding the audit of the Corporation; and

j. discuss with the external auditors, without Management being present, the quality of the Corporation's financial and accounting personnel, the completeness and accuracy of the Corporation's financial statements, and elicit comments of senior Management regarding the responsiveness of the external auditors to the Corporation's needs.

6. The Committee shall review with the external auditors (and the internal auditor if one is appointed by the Corporation) their written report containing recommendations for improvement of internal control over financial reporting and other suggestions as appropriate, and Management's response and follow-up to any identified weaknesses.

7. The Committee shall also review and approve annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

### *Compliance*

8. It is the responsibility of the Committee to review Management's process for the certification of annual and interim financial reports in accordance with required securities legislation.

9. It is the responsibility of the Committee to ascertain compliance with covenants under loan agreements.

10. The Committee shall review the Corporation's compliance with all legal and regulatory requirements as it pertains to financial reporting, taxation, internal control over financial reporting, and any other area the Committee considers to be appropriate relative to its mandate or as may be requested by the Board of Directors.

### *Other Matters*

11. It is the responsibility of the Committee to review and approve the Corporation's hiring policies regarding partners, employees, and former partners and employees of the present and external auditors of the Corporation.

12. The Committee may also review any other matters that the Audit Committee feels are important to its mandate or that the Board chooses to delegate to it.

13. The Committee shall undertake annually a review of this mandate and make recommendations to the Policy and Board Governance Committee as to proposed changes.

### *Composition*

14. This Committee shall be composed of at least three individuals appointed by the Board from amongst its members, all of which members will be independent (within the meaning of Section 1.4 and 1.5 of National Instrument 52-110 *Audit Committees* ("NI 52-110")) unless the Board determines to rely on an exemption in NI 52-110. "Independent" generally means free from any business or other direct or indirect material relationship with the Corporation that could, in the view of the Board, be reasonably expected to interfere with the exercise of the member's independent judgment.

15. The Chair of the Committee is appointed by the Board of Directors.

16. A quorum shall be a majority of the members of the Committee.

17. All of the members must be financially literate within the meaning of NI 52-110 unless the Board has determined to rely on an exemption in NI 52-110. Being "financially literate" means members have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements.

### *Meetings*

18. The Committee shall meet at least four times per year and/or as deemed appropriate by the Committee Chair.

19. The Committee shall meet not less than quarterly with the auditors, independent of the presence of Management.

20. Agendas, with input from Management, shall be circulated to Committee members and relevant Management personnel along with background information on a timely basis prior to the Committee meetings.

21. The Chief Executive Officer and the Chief Financial Officer or their designates shall be available to attend at all meetings of the Committee upon the invitation of the Committee.

22. The Vice President, Controller and such other staff as appropriate to provide information to the Committee shall attend meetings upon invitation by the Committee.

### *Reporting / Authority*

23. Following each meeting, in addition to a verbal report, the Committee will report to the Board by way of providing copies of the minutes of such Committee meeting at the next Board meeting after a meeting is held (these may still be in draft form).

24. Supporting schedules and information reviewed by the Committee shall be available for examination by any Director.

25. The Committee shall have the authority to investigate any financial activity of the Corporation and to communicate directly with the internal and external auditors. All employees are to cooperate as requested by the Committee.

26. The Committee may retain, and set and pay the compensation for, persons having special expertise and/or obtain independent professional advice to assist in fulfilling its duties and responsibilities at the expense of the Corporation.

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