ARC RESOURCES LTD

2021

Celebrating 25 Years of

Canadian Energy

Annual Information Form

March 10, 2022

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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, 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;

Common shares means the common shares in the capital of ARC Resources;

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

GLJ Report means the report prepared by GLJ and dated January 24, 2022, evaluating the crude oil, natural gas, and natural gas liquids reserves attributed to ARC's properties as at December 31, 2021;

Montney means our lands in northeast British Columbia comprised of the Greater Dawson, Sunrise, Sundown, Septimus, Attachie, and Red Creek areas and our lands 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 related to the novel coronavirus COVID-19 (“COVID-19”) pandemic and its impact on the global economy; risks described in the section entitled “*Risk Factors*” contained within ARC’s Management Discussion and Analysis dated February 10, 2022 (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, 2021, 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
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
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.

Currently, ARC is one of Canada's leading energy corporations and largest producer of condensate, with 2021 average production of 302,003 boe per day. 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, 2021, ARC had 522 professional, technical, and support staff, with 317 employees located in the Calgary office and 205 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

On April 6, 2021, ARC and Seven Generations completed the Business Combination, creating a new Canadian energy company. Seven Generations became a wholly-owned subsidiary of ARC, and was subsequently amalgamated with ARC on May 1, 2021.

ARC had a single operating subsidiary as at December 31, 2021. ARC Resources U.S. Corp. was incorporated under the laws of the State of Delaware in the United States on July 6, 2015, and was acquired as part of the Business Combination. ARC owns 100 per cent of the issued and outstanding shares of ARC Resources U.S. Corp.

STRATEGY

ARC's vision is to be a leading energy producer that is unique and difficult to replicate, 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 business development. 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 runs its business to prioritize 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.

2019

Annual average production of 139,126 boe per day. ARC delivered full-year average production of 139,126 boe per day in 2019, representing a five per cent increase relative to 2018. The increase in production was driven by increased natural gas production at the Sunrise Phase II facility and increased liquids-rich lower Montney production in the Greater Dawson area.

Total proved plus probable reserves of 910 MMboe identified and 164 per cent of produced reserves replaced. ARC's total proved plus probable reserves increased four per cent relative to 2018, totalling 910 MMboe as at December 31, 2019. During the year, 164 per cent of total proved plus probable reserves were replaced through organic development activities. Total proved reserves were 595 MMboe and proved producing reserves were 258 MMboe as at December 31, 2019.

Capital expenditure budget reduced to preserve balance sheet strength. In June 2019, ARC reduced its budgeted capital program to $700 million from $775 million, deferring development of the Attachie West Phase I facility. The adjusted capital budget was consistent with ARC's principles to maintain a strong balance sheet, demonstrate capital discipline amidst a volatile commodity price backdrop, and continue to deliver a sustainable dividend to shareholders.

Cash flow used in investing activities was $673.3 million and capital expenditures(1) totalled $691.5 million. ARC continued to focus on its core Montney assets in 2019, investing $691.5 million in capital expenditures. A significant focus of ARC's 2019 capital program was on long-term infrastructure projects to support profitable liquids growth in the Greater Dawson and Ante Creek areas. ARC drilled 87 wells and completed 83 wells in 2019.

Sunrise Phase II facility brought to full capacity. ARC brought its Sunrise Phase II facility to its full capacity of 180 MMcf per day in 2019, redirecting 60 MMcf per day of existing natural gas production that had previously been processed through a third-party facility to ARC's operated Sunrise Phase II facility, and bringing an incremental 60 MMcf per day of natural gas production on-stream.

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 as 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 as 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 be reducing its monthly dividend of $0.05 per share to a quarterly dividend of $0.06 per share.

Capital budget 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 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 on expanding 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 to combine 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

(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.

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.

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 $1,061.8 million. ARC’s 2021 capital program was focused on capital discipline and 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 roughly 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 allows ARC to purchase up to 72,236,753 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 30,887,800 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 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 facility 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; Lynne P. Chrumka was appointed to the position of Vice President, Geosciences; and Brian R. Groundwater was appointed to the position of Vice President, Engineering. Effective September 8, 2021, Sean W. Stuart was appointed to the position of Vice President, Capital Operations.

2022

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.

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, 2021. The statement of reserves data 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 January 24, 2022. 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 ("G&A") 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.

As per NI 51-101 product type definitions, ARC has provided reserves data for reserves classified as Shale Gas and reserves classified as Tight Oil. ARC's gas reserves in the Montney siltstone are classified as Shale Gas under NI 51-101. ARC's crude oil reserves in the Montney siltstone are classified as Tight Oil under NI 51-101.

DISCLOSURE OF RESERVES DATA

Company gross reserves information presented herein is consistent with reserves information disclosed in the February 10, 2022 news release entitled, *"ARC Resources Ltd. Reports Record Year-end 2021 Results and Reserves"* available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

Summary of 2021 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	—	487	9,962	158,983	169,433	47,933	1,952,153	2,000,085	502,780
Developed Non-producing	—	—	407	19,310	19,718	2,485	177,357	179,842	49,692
Undeveloped	—	—	8,048	213,183	221,231	—	2,467,315	2,467,315	632,450
TOTAL PROVED	**—**	**487**	**18,418**	**391,476**	**410,381**	**50,418**	**4,596,824**	**4,647,242**	**1,184,922**
PROBABLE	—	166	12,181	184,888	197,235	14,701	2,256,249	2,270,950	575,726
TOTAL PROVED PLUS PROBABLE	**—**	**653**	**30,598**	**576,364**	**607,616**	**65,118**	**6,853,073**	**6,918,191**	**1,760,648**

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	—	768	8,699	127,852	137,318	44,232	1,736,388	1,780,620	434,088
Developed Non-producing	—	8	333	16,264	16,605	2,235	167,880	170,115	44,957
Undeveloped	—	—	6,697	177,841	184,538	—	2,252,477	2,252,477	559,951
TOTAL PROVED	**—**	**775**	**15,729**	**321,957**	**338,461**	**46,467**	**4,156,745**	**4,203,212**	**1,038,996**
PROBABLE	—	252	9,866	145,355	155,473	13,973	2,014,774	2,028,747	493,597
TOTAL PROVED PLUS PROBABLE	**—**	**1,027**	**25,595**	**467,311**	**493,934**	**60,440**	**6,171,519**	**6,231,959**	**1,532,594**

1) NGLs includes associated NGLs for both Conventional and Shale/Tight Reservoirs, and includes condensate, propane, and butane.
2) Condensate and Pentanes Plus represent 62 per cent of proved producing NGLs, 66 per cent of total proved NGLs, and 67 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	7,375	6,383	5,601	5,007	4,548
Developed Non-producing	1,306	1,096	953	853	777
Undeveloped	9,477	6,606	4,770	3,555	2,719
TOTAL PROVED	**18,158**	**14,085**	**11,325**	**9,414**	**8,045**
PROBABLE	11,314	6,852	4,571	3,288	2,505
TOTAL PROVED PLUS PROBABLE	**29,472**	**20,937**	**15,895**	**12,703**	**10,549**

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	6,778	5,920	5,227	4,694	4,280
Developed Non-producing	992	831	722	645	588
Undeveloped	7,160	4,884	3,425	2,465	1,810
TOTAL PROVED	**14,929**	**11,634**	**9,374**	**7,805**	**6,679**
PROBABLE	8,615	5,174	3,420	2,442	1,850
TOTAL PROVED PLUS PROBABLE	**23,544**	**16,808**	**12,794**	**10,247**	**8,529**

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 2021.
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	40,243	6,551	9,154	5,508	872	18,158	3,229	14,929
Proved plus Probable Reserves	62,461	10,738	13,849	7,361	1,041	29,472	5,928	23,544

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)	21	$27.09/bbl
	Tight Oil (2)	814	$52.39/bbl
	Conventional Natural Gas (4)	82	$1.79/Mcf
	Shale Gas (4)	10,407	$2.62/Mcf
	Total	**11,325**	**$10.90/boe**
Proved Plus Probable Reserves	Light Crude Oil and Medium Crude Oil (2)	—	—
	Heavy Crude Oil (2)(3)	24	$23.77/bbl
	Tight Oil (2)	1,270	$50.04/bbl
	Conventional Natural Gas (4)	99	$1.66/Mcf
	Shale Gas (4)	14,502	$2.48/Mcf
	Total	**15,895**	**$10.37/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, 2022 price forecasts and exchange rates which reflect current forward commodity prices as at December 31, 2021, in accordance with recent COGE Handbook changes, which state 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, 2022 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$)
2022	73.00	87.97	69.41	85.78	3.80	3.40	48.39	61.65	93.04	—	0.790
2023	69.01	81.89	65.34	79.84	3.50	3.10	32.75	49.13	86.09	3.0	0.790
2024	67.24	79.32	62.66	77.33	3.15	3.15	31.73	47.59	83.82	2.0	0.790
2025	68.58	80.91	63.94	78.89	3.21	3.21	32.36	48.55	85.49	2.0	0.790
2026	69.96	82.53	65.25	80.46	3.28	3.28	33.01	49.52	87.22	2.0	0.790
2027	71.35	84.18	66.56	82.07	3.34	3.34	33.67	50.51	88.95	2.0	0.790
2028	72.78	85.86	67.91	83.71	3.41	3.41	34.34	51.52	90.73	2.0	0.790
2029	74.24	87.58	69.30	85.39	3.48	3.48	35.03	52.55	92.54	2.0	0.790
2030	75.72	89.32	69.76	87.09	3.55	3.55	35.73	53.59	94.39	2.0	0.790
2031	77.24	91.11	71.18	88.84	3.62	3.62	36.45	54.67	96.29	2.0	0.790
Thereafter	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	2.0	0.790

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, 2021.
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 2032.

ARC's weighted average realized prices for the year ended December 31, 2021, were $4.82 per Mcf for shale gas and conventional natural gas; $75.51 per barrel for tight oil, light crude oil and medium crude oil; $55.97 per barrel for heavy crude oil; $86.04 per barrel for condensate; and $26.16 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 number of wells obtained by aggregating our working interest in each of our gross wells; 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, 2021, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2021 and as at December 31, 2020 include working interest reserves before royalties payable and without including gross royalties receivable. Key highlights include:

- The acquisition of the Kakwa asset through the Business Combination nearly doubled reserves in the total proved and total proved plus probable categories.
- Total crude oil and NGLs have increased from 23 per cent of total proved plus probable reserve volumes at December 31, 2020, to 35 per cent at December 31, 2021 as a result of the Business Combination.
- The disposition of ARC’s Pembina asset resulted in the Company no longer holding any reserves for Light Crude Oil and Medium Crude Oil.
- Continued strong well performance across ARC's Montney assets drove positive total proved and proved plus probable technical revisions in the Shale Gas and NGL categories.
- Development in the Greater Dawson, Sunrise, 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 volumes 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									
December 31, 2020	32,404	507	19,538	84,110	136,558	48,286	2,751,479	2,799,765	603,185
Extensions and Improved Recovery (4)	—	—	1,622	28,004	29,626	—	519,252	519,252	116,168
Technical Revisions	(15)	4	(719)	7,364	6,634	768	97,080	97,848	22,942
Acquisitions	—	—	243	310,020	310,263	50,323	1,652,279	1,702,602	594,030
Dispositions	(31,586)	—	—	(2,276)	(33,862)	(40,954)	(41,313)	(82,267)	(47,574)
Economic Factors	—	—	651	766	1,417	—	29,239	29,239	6,290
Production (5)	(803)	(24)	(2,916)	(36,511)	(40,254)	(8,006)	(411,192)	(419,198)	(110,120)
December 31, 2021	**—**	**487**	**18,418**	**391,476**	**410,381**	**50,418**	**4,596,824**	**4,647,242**	**1,184,922**
PROBABLE									
December 31, 2020	9,607	172	12,896	53,427	76,102	17,099	1,481,080	1,498,179	325,798
Extensions and Improved Recovery (4)	—	—	51	5,171	5,222	—	96,493	96,493	21,305
Technical Revisions	(5)	(6)	(903)	(2,044)	(2,958)	189	(43,528)	(43,339)	(10,181)
Acquisitions	—	—	38	129,729	129,767	13,311	735,872	749,182	254,630
Dispositions	(9,602)	—	—	(869)	(10,471)	(15,898)	(20,136)	(36,035)	(16,477)
Economic Factors	—	—	98	(525)	(427)	—	6,469	6,469	651
December 31, 2021	**—**	**166**	**12,181**	**184,888**	**197,235**	**14,701**	**2,256,249**	**2,270,950**	**575,726**
PROVED PLUS PROBABLE									
December 31, 2020	42,011	679	32,434	137,536	212,660	65,385	4,232,559	4,297,945	928,984
Extensions and Improved Recovery (4)	—	—	1,673	33,175	34,848	—	615,745	615,745	137,472
Technical Revisions	(19)	(2)	(1,622)	5,319	3,676	957	53,552	54,509	12,761
Acquisitions	—	—	281	439,749	440,030	63,634	2,388,150	2,451,784	848,660
Dispositions	(41,189)	—	—	(3,145)	(44,333)	(56,852)	(61,450)	(118,302)	(64,050)
Economic Factors	—	—	749	240	990	—	35,708	35,708	6,941
Production (5)	(803)	(24)	(2,916)	(36,511)	(40,254)	(8,006)	(411,192)	(419,198)	(110,120)
December 31, 2021	**—**	**653**	**30,598**	**576,364**	**607,616**	**65,118**	**6,853,073**	**6,918,191**	**1,760,648**

1) NGLs includes associated NGLs for both Conventional and Shale/Tight Reservoirs.
2) Condensate and Pentanes Plus represent 60 per cent of total proved NGLs and 61 per cent of each probable and proved plus probable NGLs in the December 31, 2020 opening balance.
3) Condensate and Pentanes Plus represent 66 per cent of total proved NGLs and 67 per cent of each probable and proved plus probable NGLs in the December 31, 2021 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)
2022	1,242	1,264
2023	863	870
2024	803	865
2025	1,027	1,089
2026	956	1,038
Remainder	617	2,234
Total: Undiscounted	5,508	7,361
Total: Discounted at 10% per Year	4,225	5,254

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 $4.2 billion compared to year-end 2020, to total $7.4 billion at year-end 2021. The increase in FDC was primarily driven by the acquisition of the Kakwa asset through the Business Combination, and was partially offset by the removal of FDC associated with the Pembina asset.

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

	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
2019	—	5,491	1,180	8,640	—	10.6	212.4	1,516.6
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

	NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2019	8,236	54,529	44,810	323,196
2020	14,114	49,694	58,415	317,910
2021	173,397	213,183	391,121	632,450

Probable Undeveloped Reserves

	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
2019	—	2,877	1,476	10,182	—	6.4	64.6	1,106.7
2020	—	2,988	2,023	9,292	—	7.0	221.4	1,095.4
2021	—	—	358	8,396	—	—	774.7	1,613.2

	NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2019	4,468	37,427	16,717	236,007
2020	14,305	40,796	53,225	236,815
2021	107,186	140,923	236,667	418,181

As of December 31, 2021, undeveloped reserves represented 53 per cent of total proved reserves and 60 per cent of proved plus probable reserves. Over 48 per cent of the proved plus probable undeveloped reserves are located in the Kakwa area, with the rest located in our Montney assets of northeast British Columbia and other areas in northern Alberta. We have planned a program for the development of a portion of the undeveloped reserves in 2022 and 2023, 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 705 total proved, undeveloped locations assigned to be developed in ARC's core properties over the next five to eight years in the 2021 evaluation which account for 632 MMboe of reserves volumes. In addition to these total proved undeveloped locations are 232 future development locations assigned probable reserves only, an incremental 33 per cent, which extended the timeline to develop these reserves over the next seven to nine years. These probable locations and additional probable reserves assigned to proved locations account for 418 MMboe. The total proved plus probable undeveloped volumes account for 1,051 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 2022 and 2023, as well as in years beyond 2023, 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 water breakthrough or 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 and expensive 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 properties 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, 2021, ARC had 2,899 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, 2021	505.1	125.2
Anticipated to be paid in 2022	15.0	13.6
Anticipated to be paid in 2023	10.1	8.3
Anticipated to be paid in 2024	10.1	7.6

(1) Costs have been discounted in the financial statements at a liability-specific risk-free rate of 1.7 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 for shut-in and producing wells, facilities, and pipelines to restore properties that have been disturbed by ARC's operations to the standard imposed by the applicable regulatory authorities. Abandonment and reclamation costs for our property, plant and equipment ("PP&E") and exploration and evaluation assets ("E&E") are included in ARC's 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 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 Oil and Gas Commission ("BCOGC"). 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 $1,041.5 million (undiscounted) and $85.7 million (discounted at 10 per cent) for abandonment and reclamation costs for all active assets with attributed reserves. Refer to Note 17 "*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 properties as at December 31, 2021. Information in respect of gross and net acres and well counts are as at December 31, 2021. 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, 2021 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 properties described below are all located in the Western Canadian Sedimentary Basin and onshore within the Canadian provinces of British Columbia and Alberta. 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, 2021, 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 90 per cent in approximately 375,196 gross hectares (339,465 net hectares), which includes land holdings of 1,011 net Montney sections. ARC drilled 78 gross operated wells in 2021 within the region, with an average working interest of 100 per cent. ARC owns and operates approximately 851 MMcf per day of natural gas and 73,000 barrels per day of liquids processing capacity through its 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 236,440 gross hectares (230,983 net hectares), which includes land holdings of 663 net Montney sections. ARC drilled 63 gross operated wells in 2021 within the region, with an average working interest of 100 per cent. ARC owns and operates approximately 735 MMcf per day of natural gas and 31,500 barrels per day of liquids 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, 2021.

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	355	267	174	127	834	758	232	176
British Columbia	118	117	6	5	514	513	148	141
Total [3]	473	384	180	132	1,348	1,271	380	317

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, 2021.

Undeveloped Hectares

	Gross	Net
Alberta	243,290	196,599
British Columbia	164,871	161,297
Total	408,161	357,896

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 2022. There are no material expiries in our core holdings in 2022.

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, interest rates, and power prices 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 19 *"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)	560	90
Crude Oil and NGLs (Mbbl/d)	18	7
Estimated Cost ($ millions)	646	368

ARC expects to fulfill these commitments through ongoing exploration and development activities subject to our ongoing development plans, well performance, and disruptions or constraints at facilities and pipelines.

Total proved reserves comprise 67 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)	483	84
Crude Oil and NGLs (Mbbl/d)	3	—
Estimated Cost ($ millions)	491	256

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.

Additional disclosure related to such commitments, as well as ARC's other financial contracts as at December 31, 2021, are set forth in Note 24 *"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 $5.6 billion of income tax pools for federal tax purposes at December 31, 2021. In 2021, ARC recognized a current income tax expense of $33.7 million. For 2022, ARC expects current income tax expense to range from one per cent to six 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 20 "*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, 2021.

($ millions)	Alberta	British Columbia	Total
Property Acquisition (Disposition) Costs, Net [1]			
Proved Properties	(79.1)	—	(79.1)
Unproved Properties	—	0.5	0.5
Exploration Costs [2]	—	2.3	2.3
Development Costs [3]	588.9	407.0	995.9
Costs Incurred	**509.8**	**409.8**	**919.6**

1) Represents acquisition costs net of disposition proceeds and property swaps. 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 includes costs of land acquired ($nil).
3) Represents additions to PP&E and includes costs of land acquired ($nil).

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following tables set forth the gross and net development wells that ARC participated in during the year ended December 31, 2021.

By Well Type	Development Wells [1]		Total [1][2]	
	Gross	Net	Gross	Net
Crude Oil	8	8.00	8	8.00
Natural Gas	133	133.00	133	133.00
Total	**141**	**141.00**	**141**	**141.00**

1) Number of wells based on rig release dates.
2) ARC did not drill any exploration wells, dry holes, or stratigraphic test wells for the year ended December 31, 2021.

PRODUCTION ESTIMATES

The following tables set out the GLJ forecast of the volume of production estimated for the year ended December 31, 2022, 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	—	—	—	—	110	105	20,265	17,477	402,565	365,686	98,641	82,780	169,223	146,745
Dawson	—	—	—	—	—	—	—	—	329,330	308,456	11,948	11,110	66,836	62,519
Other Properties	—	—	75	189	6,871	5,806	2,205	2,009	455,435	414,170	10,936	9,282	94,155	84,641
Total Proved	**—**	**—**	**75**	**189**	**6,981**	**5,911**	**22,469**	**19,487**	**1,187,331**	**1,088,312**	**121,525**	**103,172**	**330,215**	**293,905**

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	—	—	—	—	11	11	462	376	29,938	27,457	7,956	6,752	13,034	11,401
Dawson	—	—	—	—	—	—	—	—	8,246	7,488	433	396	1,807	1,644
Other Properties	—	—	1	4	1,089	909	30	28	39,229	34,500	1,434	1,273	9,067	7,941
Total Probable	**—**	**—**	**1**	**4**	**1,100**	**920**	**491**	**404**	**77,413**	**69,445**	**9,824**	**8,421**	**23,908**	**20,986**

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	—	—	—	—	122	116	20,726	17,853	432,503	393,143	106,597	89,531	182,257	158,146
Dawson	—	—	—	—	—	—	—	—	337,576	315,944	12,381	11,506	68,644	64,163
Other Properties	—	—	76	193	7,960	6,715	2,234	2,037	494,664	448,670	12,370	10,555	103,222	92,581
Total Proved plus Probable	**—**	**—**	**76**	**193**	**8,081**	**6,831**	**22,961**	**19,890**	**1,264,743**	**1,157,757**	**131,348**	**111,592**	**354,123**	**314,891**

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 2021				Year Ended
	March 31	June 30	September 30	December 31	2021
Average Daily Production [1]					
Light and Medium Crude Oil (bbl/d)[2]	5,142	3,551	296	20	2,233
Heavy Crude Oil (bbl/d)	202	248	249	217	229
Tight Oil (bbl/d)	8,303	7,860	8,094	7,620	7,973
Conventional Natural Gas (MMcf/d)	14.0	448.5	480.5	464.2	353.4
Shale Gas (MMcf/d)	780.1	754.6	819.0	828.6	795.8
NGLs (bbl/d) [3]	24,432	123,479	128,430	122,519	100,042
Condensate (bbl/d)	13,812	73,459	77,539	74,220	59,958
Other NGLs (bbl/d) [4]	10,620	50,020	50,891	48,299	40,084
Total (boe/d)	170,430	335,701	353,657	345,831	302,003
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)[2]	65.98	75.25	82.53	—	71.55
Heavy Crude Oil ($/bbl)	47.64	51.80	53.33	71.26	55.97
Tight Oil ($/bbl)	63.94	74.14	77.98	91.21	76.61
Conventional Natural Gas ($/Mcf)	4.91	3.57	4.89	7.96	5.67
Shale Gas ($/Mcf)	4.60	3.20	4.55	5.61	4.44
NGLs ($/bbl) [3]	53.27	55.37	62.81	69.60	62.05
Condensate ($/bbl)	71.59	77.93	85.72	96.90	86.04
Other NGLs ($/bbl) [4]	29.45	22.19	27.92	27.65	26.16
Total ($/boe)	34.25	34.90	41.88	50.87	41.48
Royalties Paid					
Light and Medium Crude Oil ($/bbl)[2]	2.48	7.10	7.24	—	4.19
Heavy Crude Oil ($/bbl)	0.42	1.34	0.61	0.15	0.66
Tight Oil ($/bbl)	4.22	8.01	10.48	14.77	9.30
Conventional Natural Gas ($/Mcf)	0.07	(0.09)	0.00	0.15	0.02
Shale Gas ($/Mcf)	0.19	0.10	0.22	0.52	0.26
NGLs ($/bbl) [3]	3.85	7.20	7.24	10.33	7.98
Condensate ($/bbl)	4.70	11.02	10.88	15.07	11.88
Other NGLs ($/bbl) [4]	2.73	1.59	1.70	3.05	2.14
Total ($/boe)	1.69	3.02	3.38	5.44	3.64
Operating Expense [5]					
Light and Medium Crude Oil ($/bbl)[2]	26.31	26.39	34.44	—	30.66
Heavy Crude Oil ($/bbl)	9.12	7.45	3.35	11.50	7.66
Tight Oil ($/bbl)	4.88	6.02	5.15	5.97	5.50
Conventional Natural Gas ($/Mcf)	4.64	0.97	0.62	0.81	0.81
Shale Gas ($/Mcf)	0.41	0.50	0.41	0.41	0.43
NGLs ($/bbl) [3]	3.88	4.60	4.52	3.80	4.21
Condensate ($/bbl)	4.11	4.41	5.40	3.91	4.33
Other NGLs ($/bbl) [4]	3.57	4.88	3.19	3.64	4.04
Total ($/boe)	3.85	4.53	3.58	3.50	3.86

Production History - continued	Three Months Ended 2021				Year Ended
	March 31	June 30	September 30	December 31	2021
Transportation Expense					
Light and Medium Crude Oil ($/bbl)(2)	1.92	1.99	(0.45)	—	2.66
Heavy Crude Oil ($/bbl)	0.03	0.09	0.10	0.01	0.06
Tight Oil ($/bbl)	3.44	3.29	3.13	2.18	3.02
Conventional Natural Gas ($/Mcf)	0.64	1.17	1.29	2.14	1.52
Shale Gas ($/Mcf)	0.58	0.69	0.72	0.43	0.61
NGLs ($/bbl) (3)	5.20	3.47	3.92	4.25	3.96
Condensate ($/bbl)	5.56	4.07	4.24	3.71	4.10
Other NGLs ($/bbl) (4)	4.74	2.58	3.43	5.08	3.75
Total ($/boe)	3.70	4.49	4.93	5.47	4.79
Netback Received					
Light and Medium Crude Oil ($/bbl)(2)	35.27	39.77	41.30	—	34.04
Heavy Crude Oil ($/bbl)	38.07	42.92	49.27	59.60	47.59
Tight Oil ($/bbl)	51.40	56.82	59.22	68.29	58.79
Conventional Natural Gas ($/Mcf)	(0.44)	1.52	2.98	4.86	3.32
Shale Gas ($/Mcf)	3.42	1.91	3.20	4.25	3.14
NGLs ($/bbl) (3)	40.34	40.10	47.13	51.22	45.90
Condensate ($/bbl)	57.22	58.43	65.20	74.21	65.73
Other NGLs ($/bbl) (4)	18.41	13.14	19.60	15.88	16.23
Total ($/boe)	25.01	22.86	29.99	36.46	29.19

1) Before deduction of royalties and including royalty interests.
2) For the three months ended December 31, 2021, light and medium crude oil average net production prices received, royalties paid, operating and transportation expenses, and netback received have been omitted on the basis that they are not meaningful due to the low average daily production volume.
3) NGLs as defined by GLJ which includes condensate, butane, ethane, and propane.
4) Other NGLs as defined by ARC includes butane, ethane, and propane but excludes condensate.
5) 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 52 per cent and 48 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.

MARKETING ARRANGEMENTS

Below are details on marketing arrangements for our crude oil, natural gas, and NGLs production. For more information on financial contractual obligations relating to ARC's transportation agreements, see Note 24 "*Commitments and Contingencies*" in the financial statements, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

Natural Gas

During 2021, ARC continued its marketing strategy of maintaining a high level of direct control and diversification of marketing and transportation arrangements for our natural gas production.

ARC's average realized natural gas price for 2021 was $4.82 per Mcf as compared to $2.26 per Mcf for 2020. This price was achieved with a portfolio mix that on average through the year received US Midwest index-based pricing for 43 per cent, AECO index-based pricing for 27 per cent, Pacific Northwest index-based pricing for nine per cent, US Gulf Coast index-based for eight per cent, Station 2 index-based pricing for eight per cent, and Dawn index-based pricing for five per cent of total production, respectively.

Our natural gas is sold under contracts of various terms at market-based pricing in the regions into which we deliver.

Crude Oil and Natural Gas Liquids

Our liquids production in 2021 comprised approximately 27 per cent light crude oil (greater than 35° API), two per cent medium crude oil (25° to 35° API), less than one per cent heavy crude oil (less than 25° API), and 70 per cent condensate and other NGLs.

During 2021, our average realized sales prices were $75.78 per barrel for light and medium crude oil, $51.09 per barrel for heavy crude oil, and $62.05 per barrel for NGLs, including free condensate; these prices compare to 2020 prices of $42.91 per barrel for light and medium crude oil, $25.30 per barrel for heavy crude oil, and $33.56 per barrel for NGLs, including free condensate.

Our crude oil is sold under contracts of varying terms of up to one year, based on market-sensitive pricing terms. The majority of ARC's NGLs are sold on multi-year contracts at market-based pricing. Industry pricing benchmarks for crude oil and NGLs are continuously monitored to optimize our netback.

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 693,516,216 common shares and no preferred shares were outstanding as at December 31, 2021.

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 has established an NCIB allowing the Company to purchase up to 72,236,753 of its outstanding common shares, representing 10 per cent of its public float, over a 12-month period commencing September 1, 2021 and expiring no later than August 31, 2022. 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. As of December 31, 2021, ARC had repurchased a total of 30,887,800 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, 2021, we had an 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 $1.8 billion outstanding at December 31, 2021, comprised of $1.7 billion of long-term debt, and a working capital deficit of $123.4 million.

Borrowings under the syndicated credit facility bear interest at bank prime or, at ARC's option, Canadian dollar bankers' acceptances or US dollar LIBOR loans plus a stamping fee. At the option of ARC, the lenders will review the credit facility each year and determine whether they will extend the current maturity date for another year. 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 maturity date of the credit facility is October 27, 2025.

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 15 "*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, 2021, 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 18 *"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.

CORPORATE SOCIAL RESPONSIBILITY

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 progressive energy leader. With a long-term vision and 25-year history, we are dedicated to building a sustainable business that supports the transition to a low-carbon economy. Our approach centers on finding the most efficient way to produce energy, while supporting the economic and social well-being of the communities that we work in. 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) foster 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 strong link between executive compensation and performance, including incorporating ESG metrics into the determination of compensation levels.

Disclosure

We recognize the importance of comprehensive and transparent disclosure of our progress towards ESG targets. To support our disclosure efforts, we publish a biennial ESG Report to measure and report on our performance. In 2021, we released an ESG Performance Update to provide highlights on our ESG performance between full reports.

Where possible, we measure our performance using 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. Originally awarded by Equitable Origin (EO) in 2019, the certification was granted following a comprehensive and independent process that included site-level assessments and discussions with key stakeholders and Indigenous communities. The standard acknowledges ARC's top-tier ESG performance and commitment to continuous improvement.

For more information on ARC's ESG performance and for the latest 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 10, 2022 are set out below.

Directors Name and Municipality of Residence	Director Since [1]	Principal Occupation During Past Five Years
Harold N. Kvisle Calgary, Alberta, Canada	2009 (Chair) Independent	Mr. Kvisle is the Chair of ARC's Board of Directors, a position he has held since January 1, 2016.
Marty L. Proctor Calgary, Alberta, Canada	2021 Vice Chair 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.
Farhad Ahrabi Houston, Texas, USA	2019 Independent	Mr. Ahrabi is an independent business person and the former Chief Executive Officer of Cameron LNG LLC.
Carol T. Banducci Mississauga, Ontario, Canada	2021 Independent	Ms. Banducci is an independent business person. Prior to March 2021, she held the position of Executive Vice President and Chief Financial Officer of IAMGOLD Corporation.
David R. Collyer Calgary, Alberta, Canada	2016 Independent	Mr. Collyer is an independent business person.
Susan C. Jones Calgary, Alberta, Canada	2021 Independent	Ms. Jones is an independent business person. Prior to 2020, Ms. Jones was Executive Vice President and Chief Executive Officer of Nutrien's Potash Business Unit.
William J. McAdam Scottsdale, Arizona, USA	2021 Independent	Mr. McAdam is an independent business person.
Michael G. McAllister Calgary, Alberta, Canada	2020 Independent	Mr. McAllister is an independent business person. Prior to 2020, he held the position of Executive Vice President and Chief Operating Officer of Ovintiv Inc. (formerly Encana Corporation).
Kathleen M. O'Neill Toronto, Ontario, Canada	2009 Independent	Ms. O'Neill is an independent business person.
M. Jacqueline Sheppard Calgary, Alberta, Canada	2021 Independent	Ms. Sheppard is an independent business person.
Leontine van Leeuwen-Atkins Calgary, Alberta, Canada	2021 Independent	Ms. Atkins is an independent business person. Prior to 2020, she was a Partner at KPMG Canada.
Terry M. Anderson Calgary, Alberta, Canada	2020 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) The term of each director is until the next annual meeting of shareholders.

As at December 31, 2021, the Directors and Officers of ARC Resources, as a group, beneficially owned or controlled 1,950,379 common shares or approximately 0.28 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 10, 2022 are set out below.

Officers	
Name and Municipality of Residence	**Office Held and Principal Occupation During Past Five Years**
Terry M. Anderson Calgary, Alberta, Canada	**President and Chief Executive Officer** 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 Calgary, Alberta, Canada	**Senior Vice President and Chief Financial Officer** 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 Calgary, Alberta, Canada	**Senior Vice President and Chief Operating Officer** 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. Prior to March 2017, he was the Manager, Engineering.
Larissa M. Conrad Calgary, Alberta, Canada	**Senior Vice President and Chief Development Officer** Ms. Conrad is the Senior Vice President and Chief Development Officer. From April 2021 to January 2022, she was the Senior Vice President, Development. From December 2019 to April 2021, she held the position of Vice President, Development and Planning. Prior to December 2019, she was the Vice President, Engineering and Planning.
Ryan V. Berrett Calgary, Alberta, Canada	**Senior Vice President, Marketing** Mr. Berrett is the Senior Vice President, Marketing. Prior to January 2022, he was the Vice President, Marketing.
Lisa A. Olsen Calgary, Alberta, Canada	**Senior Vice President, People and Corporate** 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.
Grant A. Zawalsky (1) Calgary, Alberta, Canada	**Corporate Secretary** Mr. Zawalsky is the Vice Chairman and Partner at Burnet, Duckworth & Palmer LLP (law firm). Prior to February 2022, he was the Managing Partner.
Sean R. A. Calder Calgary, Alberta, Canada	**Vice President, Production** Mr. Calder is the Vice President, Production.
Kristin L. Cerny Calgary, Alberta, Canada	**Vice President, Finance** Ms. Cerny is the Vice President, Finance. Prior to April 2021, she was the Manager, Treasury and Risk Management.
Katherine J. Gomes Calgary, Alberta, Canada	**Vice President, Controller** Ms. Gomes is the Vice President, Controller. Prior to January 2022, she was the Controller.
Brian R. Groundwater Calgary, Alberta, Canada	**Vice President, Engineering and Geoscience** Mr. Groundwater is the Vice President, Engineering and Geoscience(2). Prior to March 2022, he was the Vice President, Engineering. From January 2018 to April 2021, he held the position of Manager, Engineering. Prior to January 2018, he was the Manager, Alberta Plains & Saskatchewan at Vermilion Energy.
Sean W. Stuart Calgary, Alberta, Canada	**Vice President, Capital Operations** Mr. Stuart is the Vice President, Capital Operations. From April 2017 to September 2021, he held the position of Manager, Completions. Prior to April 2017, he was the Manager, Production Engineering.

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.
2) Ms. Chrumka was appointed Vice President, Geosciences upon close of the Business Combination and resigned her office effective March 11, 2022.

MEMBERSHIP OF BOARD COMMITTEES

The following chart sets out the membership of the committees of the Board of Directors as at March 10, 2022.

Name of Director	Audit	Human Resources & Compensation	Policy & Board Governance	Risk	Safety, Reserves & Operational Excellence
Farhad Ahrabi	√			Chair	
Carol T. Banducci	√			√	
David R. Collyer		Chair	√		√
Susan C. Jones		√			√
Harold N. Kvisle					
William J. McAdam				√	√
Michael G. McAllister		√			Chair
Kathleen M. O'Neill	Chair		√		
Marty L. Proctor				√	√
M. Jacqueline Sheppard		√	Chair		
Leontine van Leeuwen-Atkins	√			√	

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 in 2020. In his role, Mr. Anderson has overall accountability for the Company's strategy and 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 and has held progressively senior roles including Senior Vice President, Engineering and Land, and Senior Vice President, Operations. 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. He holds a Bachelor of Science degree in Petroleum Engineering from the University of Wyoming.

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 and tax functions. His responsibility increased with the addition of the capital markets and investor relations functions to his expanded role of Vice President, Finance and Capital Markets in 2019. Previously, he was CFO 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 20 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 joining 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 more than 20 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 2020 to 2021. Prior to joining ARC, she led fiscal, regulatory, and environmental policy at a major Canadian crude oil and natural gas producer.

In 2020, Ms. Conrad was named to the Global Female Influencer 275 list by the Energy Council. She acted as Co-Chair for the United Way Leader's Cabinet in Calgary in 2020 and 2021, and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). She has a Bachelor of Science degree in Mechanical Engineering from the University of Waterloo and a Certificate of Management Excellence from Harvard Business School, Executive Education.

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, office services, and information management. 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.

In 2020, Ms. Olsen was named to the Global Female Influencer 275 list by the Energy Council. Currently, she serves as Board Chair for Enviros and as a 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.

Grant A. Zawalsky, B. Comm, LL.B
CORPORATE SECRETARY

Mr. Zawalsky acts as Corporate Secretary for ARC Resources. He is 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. Currently, he serves as the Governor of the Calgary Petroleum Club. Mr. Zawalsky acts a director for several public and private energy companies including, NuVista Energy Ltd., PrairieSky Royalty Ltd., and Whitecap Resources Ltd.

Sean R. A. Calder, P.L. (Eng.), R.E.T.
VICE PRESIDENT, PRODUCTION

Mr. Calder is ARC's Vice President, Production. In his role, he is responsible for all aspects of field production operations, including production engineering, production systems, maintenance, and asset integrity. He has more than 20 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 Petroleum Engineering Technology degree from the Southern Alberta Institute of Technology (SAIT).

Kristin L. Cerny, B.B.A, 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 nearly 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. She is a Chartered Financial Analyst charterholder and is currently pursuing a Master of Science in Accounting from DePaul University. Ms. Cerny also holds a Bachelor of Business Administration in Finance from the University of Notre Dame.

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.

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.

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 10, 2022, the members of the Audit Committee are Kathleen O'Neill (Chair), Farhad Ahrabi, Carol Banducci, and Leontine van Leeuwen-Atkins; each is independent and financially literate within the meaning of NI 52-110. Additionally, Kathleen O'Neill, Carol Banducci, and Leontine van Leeuwen-Atkins are considered financial experts, having accounting and related financial management experience.

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

Kathleen M. O'Neill

Ms. O'Neill has 40 years' experience in accounting and financial services. She has extensive expertise in both corporate and not-for-profit board governance, specializing in audit, compensation, operational, and financial risk. Currently, Ms. O'Neill is a Director of Finning International Inc. and Ontario Teachers' Pension Plan. Prior to her retirement in 2005, Ms. O'Neill was Executive Vice President, Personal & Commercial Development and Head of Small Business Banking at the Bank of Montreal Financial Group. In her role, she held overall accountability for several major business units. Previously, she was a Partner at PricewaterhouseCoopers, where she worked for 19 years. Ms. O'Neill is a Chartered Professional Accountant, a Fellow of the Institute of Chartered Professional Accountants of Ontario, and holds the Institute of Corporate Directors designation. She holds a Bachelor of Commerce degree from the University of Toronto.

Farhad Ahrabi

Mr. Ahrabi has more than 35 years of experience in international energy operations with extensive expertise in liquefied natural gas ("LNG"). His knowledge extends to joint venture management and operational excellence in global upstream and midstream operations. Mr. Ahrabi retired from his most recent role as Chief Executive Officer of Cameron LNG LLC in January 2022. Previously, Mr. Ahrabi spent 29 years with the BG Group (now part of Royal Dutch Shell) where he held several executive positions. Within Canada, Mr. Ahrabi spent three years representing a major international joint venture partner in assessing LNG opportunities in British Columbia. Mr. Ahrabi holds a Bachelor of Science 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 experience with a focus in operational, corporate, and senior leadership roles around the world. 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. She also served as Chair of Niobec Inc. prior to orchestrating the $530 million sale of the business. 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 on the board of directors of Hudbay Minerals Inc. She is a member of the National Association of Corporate Directors (USA), the Institute of Corporate Directors, the Financial Executives Institute of Canada and a past member of the Canadian Board Diversity Council. Ms. Banducci holds a Bachelor of Commerce from the University of Toronto.

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, Points.com (Audit Committee Chair) and EPCOR Utilities Inc. From 2006 to 2019, she was a partner with KPMG. 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 Seven Generations. Ms. Atkins is a member of the executive 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 Chartered Professional Accountant and Chartered Accountant designations, as well as the Institute of Corporate Directors designation.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The Audit Committee has not adopted specific policies and procedures for the engagement of non-audit services and pre-approves each such engagement or type of engagement individually.

PricewaterhouseCoopers LLP acted as ARC's external auditor for the fiscal years ended December 31, 2021 and 2020. 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		2021		2020
Audit Fees	$	1,166,300	$	683,891
Audit Related Fees (1)	$	26,750	$	42,800
All Other Fees (2)	$	252,150	$	52,410

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 environmental and sustainability reporting.

CONFLICTS OF INTEREST

The Board of Directors has adopted a Code of Business Conduct and Ethics and a Code of Ethics for Senior Financial Officers (the "Codes"). In general, the private investment activities of employees, Directors, and Officers are not prohibited, however, should an existing investment pose a potential conflict of interest, the potential conflict is required by the Codes to be disclosed to the President and Chief Executive Officer, or the Board of Directors. Any other activities of employees which pose a potential conflict of interest are also required by the Codes to be disclosed to the President and Chief Executive Officer, or the Board of Directors. Any such potential conflicts of interests will be dealt with openly with full disclosure of the nature and extent of the potential conflicts of interests with the Corporation.

It is acknowledged in the Codes that employees, Officers, and Directors may be Directors or Officers of other entities engaged in the crude oil and natural gas industry, and that such entities may compete directly or indirectly with the Corporation. No assurance can be given that opportunities identified by Directors of ARC Resources will be provided to us. Passive investments in public or private entities of less than one per cent of the outstanding shares will not be viewed as "competing" with the Corporation. Any Director, Officer, or employee of ARC Resources which is a director or officer of any entity engaged in the crude oil and natural gas industry shall disclose such occurrence to the Board of Directors. Any Director, Officer or employee of ARC Resources who is actively engaged in the management of, or who owns an investment of one per cent or more of the outstanding shares, in public or private entities shall disclose such holding to the Board of Directors. In the event that any circumstance should arise as a result of such positions or investments being held or otherwise which in the opinion of the Board of Directors constitutes a conflict of interest which reasonably affects such person's ability to act with a view to the best interests of the Corporation, the Board of Directors will take such actions as are reasonably required to resolve such matters with a view to the best interests of the Corporation. Such actions, without limitation, may include excluding such Directors, Officers, or employees from certain information or activities of the Corporation.

The *Business Corporations Act* (Alberta) provides that in the event that an Officer or Director is a party to, or is a Director or an Officer of or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such Officer or Director shall disclose the nature and extent of his or her interest and refrain from voting to approve such contract or transaction.

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 $12.0 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 $200.0 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. alleging infringement of Steelhead's patent related to a floating near-shore LNG facility and seeking damages in excess of $250 million. ARC has 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 have also brought a motion for summary trial related to Steelhead's infringement allegations, which is expected to be heard in the second quarter of 2022. ARC does not expect the outcome of the claim to result in a material outflow of resources by ARC.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as described below, 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.

Upon closing of the Business Combination, Marty L. Proctor (Seven Generations' former President and Chief Executive Officer) became the Vice-Chair of the ARC Board of Directors. Mr. Proctor was party to an employment agreement with Seven Generations that provided for payments to him in connection with the termination of his employment or a change of control event of Seven Generations. On closing of the Business Combination, Mr. Proctor was paid the sum of approximately $3.5 million in respect of severance amounts owing to him under his employment agreement.

In addition to the foregoing, Mr. Proctor held certain Seven Generations incentive awards at closing of the Business Combination that were generally treated in the same manner as those held by other employees of Seven Generations who did not continue their employment with ARC. On closing of the Business Combination, Mr. Proctor was paid the sum of approximately $5.8 million in respect of amounts owing to him on settlement of his Seven Generations incentive awards.

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	**2021**	**2020**	**2019**
January	—	$0.05	$0.05
February	—	$0.05	$0.05
March	$0.06	$0.02	$0.05
April	—	—	$0.05
May	—	—	$0.05
June	$0.06	$0.06	$0.05
July	—	—	$0.05
August	—	—	$0.05
September	$0.066	$0.06	$0.05
October	—	—	$0.05
November	—	—	$0.05
December	$0.10	$0.06	$0.05
Total	**$0.286**	**$0.30**	**$0.60**

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 2021 of the common shares on the TSX for the periods indicated (as quoted by Bloomberg).

Toronto Stock Exchange	High ($)	Low ($)	Volume
January	7.34	5.91	34,356,609
February	8.25	6.32	66,901,602
March	8.50	7.33	92,500,492
April	8.02	7.34	76,732,030
May	9.36	7.93	65,130,173
June	10.63	9.32	66,597,232
July	10.69	9.12	46,669,977
August	9.14	7.73	62,955,501
September	11.87	9.18	81,538,473
October	12.43	11.29	63,732,016
November	13.15	11.21	72,223,234
December	11.87	10.65	63,939,853

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 western Canadian crude oil and natural gas industry. All current legislation is a matter of public record and we are unable to predict what additional laws, regulations, 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 of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts, 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

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 declines in crude oil prices caused by the emergence of the COVID-19 pandemic. In the first quarter of 2022, crude oil prices have risen to the highest levels since 2014 due to tight supply and a resurgence in global demand as well as increased geopolitical risk. The Organization of Petroleum Exporting Countries forecasts robust growth in world crude oil demand in 2022, despite newly emerging COVID-19 variants, expected interest rate increases in major economies, and other uncertainties with respect to the world economy.

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 condensate 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

Under the Canadian Constitution, 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. However, recent years have seen a perceived lack of policy and regulatory certainty in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines may also require approvals from several levels of government in the United States.

Oil Pipelines

Producers negotiate with pipeline operators (or other transport operators) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers, and the price received.

The Enbridge Inc. Line 3 Replacement from Hardisty, Alberta to Superior, Wisconsin came into service in October 2021. The Line 3 Replacement, originally expected to be in-service in late 2019, faced significant permitting difficulties in the United States resulting in the two-year delay. The pipeline provides an incremental 370,000 barrels per day of export capacity from western Canada into the United States.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019 and it is expected to be in-service in December 2022; however, there continues to be uncertainty about whether the expected in-service date will be met.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge filed a federal complaint in late November 2020 in the United States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shut-down order, as the dual pipelines are in full compliance with US federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. On December 15, 2021, Enbridge moved to transfer the Attorney General's lawsuit from Michigan State Court to United States Federal Court.

Marine Tankers

The Oil Tanker Moratorium Act, which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines being built to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium.

Natural Gas and Liquefied Natural Gas

Natural gas prices in western Canada have been constrained in recent years due to increasing North American supply, limited access to markets, and limited storage capacity. Companies that secure firm access to 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 markets.

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. In October 2020, TC Energy received federal approval to expand the NGTL System and the expanded NGTL System is expected to be fully operational by April 2022.

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. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "CGL Pipeline"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

In May 2020, TC Energy sold a 65 per cent equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of February 2022, construction of the CGL Pipeline is approximately 60 per cent complete.

In addition to LNG Canada and the CGL Pipeline projects, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

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, 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 US 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 and interpretation of the USMCA could impact western Canada's crude oil and natural gas industry at large, including ARC's business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the US 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.

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 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 AND INCENTIVES

General

The provincial governments in western Canada may create incentive programs for the crude oil and natural gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays, or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of crude oil, natural gas, and NGLs, or improve environmental performance.

In addition, from time to time, including during the COVID-19 pandemic, the federal government creates incentives and other financial aid programs intended to assist businesses operating in the crude oil and natural gas industry as well as other industries in Canada.

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. The majority of ARC's assets are on Crown lands.

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>Incentive Period</th><th>Post-incentive 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 natural gas, natural gas liquids and crude oil royalty system. Based on the outcomes of this review and input received from the public, a policy announcement is expected in early 2022. Until the changes to the regime are implemented, the current system, established under the 1992 Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation, is expected to continue to apply.

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 - Incentive Period	Gas Wells - Post-incentive
Crude Oil - based on oil production	0% to 23%	N/A	N/A
Natural Gas - based on price	8% to 13%	3% or 6%	9% to 27%
Condensate	20%	3% or 6%	20%
Liquids - C2-C5	20%	3% or 6%	20%

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of the province's natural gas wells. Important programs applicable to our key properties are:

- Deep Well Royalty Credit Program, which provides a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties and is well-specific based on drilling and completion depths. During this incentive period ARC pays a minimum of three per cent or six per cent depending on the drilling depth.
- The Government of British Columbia also maintains an annual Clean Growth Infrastructure Royalty Credit Program that provides royalty credits under two categories. The "Growth" category of the program is for approved road, pipeline, or value-add infrastructure projects and is intended to facilitate increased exploration, production in under-developed areas, and to extend the drilling season. The "Sustainability" category of this program is for approved electrification infrastructure and emissions reduction projects. Electrification projects are new or retrofits of well pads, wellsite compressors, and other electrical equipment in the field. Emissions-reduction projects are installing retrofit, replacement, or new equipment that reduces or removes greenhouse gas emissions in the upstream or midstream crude oil and natural gas industry.

ENVIRONMENTAL REGULATION

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 international or interprovincial 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.

The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA, but this matter remains before the courts.

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 Surface Rights Board, 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 Ministry of Indigenous Relations began a renewal process for the Government of Alberta’s Policy on Consultation with First Nations on Land and Natural Resource Management, 2013 and the Government of Alberta’s Policy on

Consultation with Metis Settlements on Land and Natural Resource Management, 2015. In 2018, the Ministry updated the Joint Operating Procedures for Consultation on Energy Resource activities ("JOP") and associated guidelines. The JOPs and their associated guidelines were updated to clarify roles and responsibilities, internal procedures and expectation for information sharing. As a result of the update, industry can make applications to the AER (PLA, MSL, LOC) for a Crown Disposition concurrently with application to the Aboriginal Consultation Office.

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 BCOGC 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 BCOGC 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.

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 REGULATION

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 drilling and completions programs. 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 does experience induced seismicity associated with wastewater disposal at its Kakwa property. ARC proactively monitors seismicity using seismometers, follows all regulations, and adheres to industry best practices aimed at mitigating or minimizing any effects of induced seismicity. The AER continues to monitor seismic activity around the province and may extend their 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 resultant from the study; however, the government continues to work with the BCOGC 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"), in May 2018, the BCOGC issued special notification and monitoring requirements 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 BCOGC, and the suspension of operations 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 BCOGC attributed to hydraulic fracturing. The BCOGC allowed the natural gas producer to resume operations in the Montney on October 21, 2019, but their suspension demonstrates the BCOGC'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 BCOGC's monitoring and oversight of seismic risk is not limited to hydraulic fracturing. In April 2021, the BCOGC 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 BCOGC 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 - 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 Ac*t, 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 dams and require compliance under the Dam Safety Regulations and require compliance 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 BCOGC 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. Additionally, the Corporation has taken extra measures towards ensuring 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. 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. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. 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 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 also 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; (iv) the management of its operations; (v) the rate of closure activities for its liabilities; and (vi) and its compliance with administrative and regulatory requirements. These various factors then 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 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. At this time, ARC is unable to predict how the new AB LMF will affect its operations; however, any forthcoming changes may affect ARC's ability to obtain or transfer licences.

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 of 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 BCOGC oversees a Liability Management Rating Program (the "BC LMR Program"), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the BCOGC determines the required security deposits for permit holders under the OGAA. The liability management rating is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed their deemed assets (i.e., an LMR below 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

Also similar to Alberta, the BCOGC has indicated that it will move away from the BC LMR Program and move towards a more holistic assessment under the new Permittee Capability Assessment program (the "BC PCA"). The BC PCA will include an evaluation of more than only a permittee's ratio of liabilities to assets. However, details regarding the BC PCA remain forthcoming. The BCOGC has indicated that the BC PCA will be implemented by April 2022.

In 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 BCOGC 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 BCOGC, 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 Dormancy Regulation is expected to have minimal impact on ARC’s corporate liability estimate and the company’s current liability management program in British Columbia.

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 BCOGC 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 BCOGC with the power to grant these exemptions came into force on October 28, 2021.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's crude oil and natural gas industry in response to COVID-19, in May 2020 the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan, and British Columbia. These funds were administered by regulatory authorities in each province and disbursed through various provincial programs. The majority of these funds have now been allocated and disbursed.

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 results of operations and cash flows.

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.

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 Ac*t (the "GGPPA"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system for large industry and a regulatory fuel charge imposing an initial price of $20 per tonne of CO_2e. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. This ensures 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 reaches 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, such that, 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. Starting April 1, 2022, the minimum price permissible under the GGPPA is $50 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. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by 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.

As part of its efforts to provide relief to Canada's crude oil and natural gas industry in light of the COVID-19 pandemic, the federal government announced the $750 million Emissions Reduction Fund ("ERF"), intended to help the crude oil and natural gas sectors to reduce the production of methane and other GHG emissions. Funds disbursed through the ERF will primarily take the form of repayable contributions to onshore and offshore crude oil and natural gas firms. Of the $750 million in funding, $675 million was allocated to the Onshore Deployment Program, while $75 million was dedicated to the Offshore Deployment Program and the Offshore RD&D (research, development, and demonstration) Program. Natural Resources Canada expects that all funding for onshore projects will be allocated by March 2022, while funding for offshore projects will be allocated by March 2023.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers, and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

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 Act is required every five years from the date the Act came into force.

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. The federal government has indicated that urgent steps are necessary 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 April 1, 2022, the carbon tax payable in Alberta will increase from $40 to $50 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 replaces 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 one 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.

On September 1, 2020, the Government of Alberta announced $750 million in spending from the TIER fund to support projects that help industries reduce their carbon emissions. Such projects include CCUS, energy efficiency, and increased methane management initiatives. An additional $176 million in spending from the TIER fund was announced for similar GHG reduction projects on November 1, 2021.

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* (the "Alberta Methane Regulations") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* ("Directive 060"). The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. 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 $45 per tonne of CO_2e. The charge will increase to $50 per tonne of CO_2e on April 1, 2022 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.

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 greenhouse gas 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. As of November 2021, the CleanBC Industry Fund had invested $43 million in 32 projects across the province.

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 BCOGC 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 groups 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.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian crude oil and natural gas industry 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 Nation ("BRFN") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. As a result of the Blueberry Decision, the Government of British Columbia has ceased granting regulatory approvals, and, in some cases, revoked existing approvals, in the Treaty 8 claim area, for crude oil and natural gas activities. Going forward, the Blueberry Decision may have significant impacts on the regulation of industrial activities in northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties.

On October 7, 2021, the Government of British Columbia and the BRFN reached an initial agreement in response to the Blueberry Decision in which the parties agreed to negotiate a land management process for BRFN territory, and certain previously authorized forestry and crude oil and natural gas projects were put on hold pending further negotiation. Currently, the Government of British Columbia and the BRFN are in the midst of negotiations to finalize a new regime for assessment, authorization, and management of industrial activities on BRFN territory in a manner consistent with the Blueberry Decision. The long-term impacts and risks of the Blueberry Decision on the Canadian crude oil and natural gas industry and ARC 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 Cdn$100,000 made to any level of a Canadian or foreign government (including Indigenous groups), 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 the common shares is Computershare Trust Company of Canada at its principal offices in Calgary and Toronto.

MATERIAL CONTRACTS

During the year ended December 31, 2021, 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, 2021. 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.

PricewaterhouseCoopers LLP, Chartered Professional Accountants, Calgary, Alberta, have issued their audit opinion dated February 10, 2022, in respect of the Corporation’s consolidated financial statements as at and for the year ended December 31, 2021. PricewaterhouseCoopers LLP is 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 its reconciliation to cash flow used in investing activities.

	Year Ended		
($ millions)	**December 31, 2021**	**December 31, 2020**	**December 31, 2019**
Cash flow used in investing activities	**808.1**	**364.3**	**673.3**
Cash acquired upon close of Business Combination	4.9	—	—
Acquisition of crude oil and natural gas assets	(1.1)	(0.2)	(0.2)
Disposal of crude oil and natural gas assets	79.7	1.8	5.0
Change in non-cash working capital	164.7	(30.6)	(7.4)
Other PP&E[1]	5.5	7.9	20.8
Capital expenditures	**1,061.8**	**343.2**	**691.5**

(1) Other PP&E 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, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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, 2021, 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, 2021	Canada	—	15,895	—	**15,895**

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, January 24, 2022.

/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 Anderson
Terry Anderson
President and Chief Executive Officer

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

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

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

March 10, 2022

APPENDIX C

MANDATE OF THE AUDIT COMMITTEE

MANDATE OF THE AUDIT COMMITTEE (March 10, 2022)

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

i. 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; between scheduled meetings, the Chair of the Committee is authorized to approve all audit related services and non-audit services provided by the external auditors for individual engagements with estimated fees of $50,000 and under; and shall report all such approvals to the Committee at its next scheduled meeting;

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.