Creating energy for the world

2020 Annual Information Form

March 1, 2021

ARC RESOURCES LTD

TABLE OF CONTENTS

GLOSSARY OF TERMS 3

SPECIAL NOTES TO READER 4
Regarding Forward-Looking Statements 4
Access to Documents 5
Abbreviations and Conversions 5

ARC RESOURCES LTD 7
General 7
Organizational Structure 7
Strategy 7
Development of Our Business 7

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION 11
Disclosure of Reserves Data 11
Forecast Prices and Costs 14
Definitions and Notes to Reserves Data Tables 15
Reconciliations of Changes in Reserves 17
Future Development Costs 19
Undeveloped Reserves 19
Significant Factors or Uncertainties Affecting Reserves Data 21
Further Information Respecting Abandonment Obligations 21
Core Operating Areas 22
Crude Oil and Natural Gas Wells 23
Properties with No Attributable Reserves 23
Forward Contracts and Transportation Commitments 23
Tax Horizon 24
Capital Expenditures 25
Exploration and Development Activities 25
Production Estimates 25
Production History 26
Marketing Arrangements 28

SHARE CAPITAL OF ARC RESOURCES 29
Common Shares 29
Preferred Shares 29

OTHER INFORMATION RELATING TO OUR BUSINESS 30
Borrowing 30
Credit Ratings 31
Corporate Social Responsibility 31

DIRECTORS AND EXECUTIVE OFFICERS 32
Membership of Board Committees 33
Officer Biographies 34

AUDIT COMMITTEE DISCLOSURES 36
Members of the Audit Committee 36
Principal Accountant Fees and Services 37

CONFLICTS OF INTEREST 38

LEGAL PROCEEDINGS 38

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 38

DIVIDENDS 39
Dividend Policy 39
Dividend History 39

MARKET FOR SECURITIES 40

INDUSTRY CONDITIONS 41
Pricing and Marketing 41
Exports from Canada 42
Transportation Constraints and Market Access 42
Curtailment 44
International Trade Agreements 44
Land Tenure 45
Royalties and Incentives 45
Environmental Regulation 47
Hydraulic Fracturing Regulation 49
Liability Management Rating Programs 50
Climate Change Regulation 52
Indigenous Rights 54
Accountability and Transparency 54

RISK FACTORS 55

TRANSFER AGENT AND REGISTRAR 55

MATERIAL CONTRACTS 55

INTEREST OF EXPERTS 56

ADDITIONAL INFORMATION 56

APPENDIX A REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVE EVALUATOR A-1

APPENDIX B REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION B-1

APPENDIX C MANDATE OF THE AUDIT COMMITTEE C-1

GLOSSARY OF TERMS

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

ARC, We, Us, Our, Corporation means ARC Resources Ltd. and all its controlled entities as a consolidated body at the applicable time;

ARC Resources means ARC Resources Ltd., a corporation formed by amalgamation under the *Business Corporations Act* (Alberta);

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 reserve evaluator of Calgary, Alberta;

GLJ Report means the report prepared by GLJ and dated January 29, 2021 evaluating the crude oil, natural gas, and natural gas liquids reserves attributable to ARC's properties as at December 31, 2020;

Montney means our lands in northeast British Columbia comprised of the Dawson, Parkland/Tower, Sunrise, Sundown, Septimus, Attachie, and Red Creek areas and our lands in northern Alberta in the Pouce Coupe and Ante Creek 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*;

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 STATEMENTS

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events of our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are 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 are forward-looking statements 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. These statements involve 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 statements. We believe the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak 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 statements identified above, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements 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; 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 hedging 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 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, 2021 (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 these forward-looking statements, 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 continued availability of capital and skilled personnel, acquisitions of reserves and undeveloped lands; 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 statements, 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 statements 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 statements except as required by securities laws or regulations.

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 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).

To Convert From	To	Multiply By
cubic metres	cubic feet	35.315
barrels	cubic metres	0.159
cubic metres	barrels	6.290
feet	metres	0.305
metres	feet	3.281
acres	hectares	0.4047
hectares	acres	2.471

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 crude oil and natural gas corporations with average production in 2020 of 161,564 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, 2020, ARC had 422 professional, technical, and support staff, with 233 employees in the Calgary office and 189 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

ARC Resources is a sole legal entity and does not have any material subsidiaries or affiliates as of December 31, 2020.

STRATEGY

ARC's vision is to be a leading energy producer. The guiding principles upon which ARC conducts its business have created a strong foundation for superb business performance. ARC's operational excellence, robust risk management program, and strong balance sheet have positioned the Company to prudently manage volatile market conditions. ARC is committed to paying a meaningful dividend and maintaining a strong balance sheet to provide superior long-term financial returns for its shareholders. ARC has built a commodity-diverse portfolio of world-class, low-cost assets and continuously creates value and optimizes revenue through upstream and downstream business development and other commercial activities. These activities and commitments are supported by a strong culture of respect, integrity, trust, and community. ARC runs its business in a manner that prioritizes the safety of employees, 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. During this period, ARC has operated in one of the most challenging commodity price and capital market environments in the history of the Corporation.

2018

Annual average production of 132,724 boe per day. ARC achieved full-year average production of 132,724 boe per day in 2018, representing an eight per cent increase relative to 2017. The increase in production was predominantly made up of new condensate-rich production flowing through the Dawson Phase III facility, new condensate-rich wells at Attachie West, as well as new production flowing through the Sunrise Phase II gas processing facility expansion. ARC divested of assets producing approximately 4,700 boe per day of production in 2018, including its Redwater assets in the third quarter of 2018. The annual impact of the non-core dispositions to ARC's full-year 2018 production was approximately 2,100 boe per day.

Proved plus probable reserves of 879 MMboe identified and 245 per cent of produced reserves replaced. GLJ determined ARC's proved plus probable reserves increased five per cent relative to 2017, totaling 879 MMboe as at December 31, 2018. During the year, 245 per cent of proved plus probable reserves were replaced through capital development activities, and ARC had record proved producing development additions of 82 MMboe in 2018.

Capital expenditures totaled $679.4 million. During 2018, ARC invested $679.4 million in capital expenditures, before undeveloped land purchases and net acquisitions and dispositions, approximately 95 per cent of which was directed towards ARC's Montney assets. Capital investment was directed at several infrastructure projects in 2018, including, the Sunrise Phase II gas processing facility, long-term water recycling infrastructure in northeast British

Columbia, and a pipeline connecting ARC's Parkland and Dawson assets. ARC also incurred initial investments for the Dawson Phase I & II liquids-handling upgrade, the Dawson Phase IV gas processing and liquids-handling facility, and the Ante Creek 10-36 facility expansion project. ARC drilled 77 wells in 2018 (46 natural gas and liquids-rich natural gas wells, 30 crude oil wells, and one disposal well).

Commissioning of Sunrise Phase II. ARC commissioned the Sunrise Phase II gas processing facility expansion in the third quarter of 2018. Overall, execution of the expansion project was excellent, with the project being completed ahead of schedule, under budget, and with an exceptional safety record. The facility was designed to process 180 MMcf per day of natural gas; an initial 60 MMcf per day of processing capacity was in service in the fourth quarter of 2018.

Physical marketing and financial diversification program. ARC maintained its strategy to physically and financially diversify its realized natural gas prices to multiple North American downstream sales points in 2018. ARC's natural gas sales portfolio was physically and financially diversified to multiple downstream markets including US Midwest and Pacific Northwest, Henry Hub, Dawn, AECO, and Station 2 markets. Through ARC's diversification activities, an incremental $0.72 per Mcf was realized in ARC's natural gas price in 2018, and ARC's financial risk management program provided additional cash flow protection with realized cash gains recognized on ARC's natural gas risk management contracts totaling $0.81 per Mcf.

2019

Annual average production of 139,126 boe per day. ARC achieved 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 gas processing facility and increased liquids-rich lower Montney production in the greater Dawson area.

Proved plus probable reserves of 910 MMboe identified and 164 per cent of produced reserves replaced. GLJ determined ARC's proved plus probable reserves increased four per cent relative to 2018, totaling 910 MMboe as at December 31, 2019. During the year, 164 per cent of proved plus probable reserves were replaced through capital development activities. Proved producing reserves were 258 MMboe as at December 31, 2019, representing an increase of six per cent relative to 2018.

Capital budget reduced to preserve balance sheet strength. In June 2019, ARC reduced its budgeted capital program of $775 million for 2019 to $700 million. The adjusted capital budget was consistent with ARC's principles to maintain a strong balance sheet, deliver a sustainable dividend to shareholders, and demonstrate capital discipline amidst a volatile commodity price backdrop. The reduction to the 2019 capital budget related primarily to the deferral of the Attachie West Phase I gas processing and liquids-handling facility.

Capital expenditures totaled $691.5 million. ARC continued to focus on its core Montney businesses in 2019, investing $691.5 million in capital expenditures, before undeveloped land purchases and net acquisitions and dispositions. 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. 37 per cent of the capital invested in 2019 was to develop infrastructure, with the key focus being on advancing the Dawson Phase IV facility. ARC drilled 87 wells in 2019 (55 natural gas and liquids-rich natural gas wells and 32 crude oil wells).

Sunrise Phase II brought to full capacity. ARC brought its Sunrise Phase II gas processing 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 during the second quarter of 2019, and bringing the final 60 MMcf per day of natural gas production on-stream early in the fourth quarter of 2019.

Physical marketing and financial diversification program. ARC maintained its strategy to physically and financially diversify its realized natural gas prices to multiple North American downstream sales points in 2019. ARC's natural gas sales portfolio is physically and financially diversified to multiple downstream markets including US Midwest and Pacific Northwest, Henry Hub, Dawn, AECO, and Station 2 markets. Through ARC's diversification activities, an incremental $0.40 per Mcf was realized in ARC's natural gas price in 2019, and ARC's financial risk management program provided additional cash flow protection with realized cash gains recognized on ARC's natural gas risk management contracts totaling $0.44 per Mcf.

2020

Annual average production of 161,564 boe per day. ARC achieved record 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 Sunrise Phase II being brought to full facility capacity in the fourth quarter of 2019.

Proved plus probable reserves of 929 MMboe identified and 203 per cent of produced reserves replaced. GLJ determined ARC's proved plus probable reserves increased two per cent relative to 2019, totaling 929 MMboe as at December 31, 2020. During the year, 203 per cent of proved plus probable reserves were replaced through capital development activities. Total proved reserves were 603 MMboe as at December 31, 2020, increasing one per cent relative to 2019; and proved producing reserves were 268 MMboe as at December 31, 2020, representing an increase of four per cent relative to 2019.

Senior 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, ARC announced on March 13, 2020 that it would be reducing its monthly dividend of $0.05 per share to a quarterly dividend of $0.06 per share, to preserve the Company's strong financial position.

Capital budget reduced to preserve balance sheet strength. Concurrent with the dividend reduction announcement, ARC reduced its capital program of $500 million to $300 million. The adjusted capital budget was consistent with ARC's principles to maintain a strong balance sheet and demonstrate capital discipline amidst a volatile commodity price backdrop. The reduction to the 2020 capital program related primarily to the deferral of drilling and completions activities in Dawson and Ante Creek. Subsequent to this, with a sustained improvement in commodity prices, ARC increased its 2020 capital budget to $350 million.

Capital expenditures totaled $343.2 million. ARC focused on its core Montney businesses in 2020, investing $343.2 million in capital expenditures, before undeveloped land purchases and net acquisitions and dispositions. A significant focus of ARC's 2020 capital program was on efficient execution and expanding the Company's low-cost Montney business by completing the Dawson Phase IV facility in the second quarter of 2020. ARC drilled 59 wells in 2020 (45 natural gas and liquids-rich natural gas wells and 14 crude oil wells).

Commissioning of Dawson Phase IV. ARC commissioned the Dawson Phase IV gas processing and liquids-handling facility in the second quarter of 2020. The project was completed ahead of schedule, under budget, and with a perfect safety record. The facility was designed to process 90 MMcf per day of natural gas and 10,500 barrels per day of condensate and NGLs.

2021

On February 10, 2021, ARC and Seven Generations Energy Ltd. ("Seven Generations") announced that they had entered into a Business Combination Agreement to combine in an all-share transaction valued at approximately $8.1 billion, inclusive of net debt[(1)] (the "Business Combination"). The combined company will operate as ARC Resources Ltd. and remain headquartered in Calgary, Alberta with field operations in Grande Prairie, Alberta, Dawson Creek, British Columbia, and Drayton Valley, Alberta.

Seven Generations is a low-supply cost energy producer dedicated to stakeholder service, responsible development and generating strong returns from its liquids-rich Kakwa River Project in northwest Alberta. Seven Generations' corporate office is in Calgary, Alberta its operations headquarters is in Grande Prairie, Alberta and its shares trade on the TSX under the symbol "VII".

(1) For information on net debt refer to Note 16 "*Capital Management*" of ARC's audited consolidated financial statements as at and for the year ended December 31, 2020 (the "financial statements") and to the section entitled and "*Capitalization, Financial Resources and Liquidity*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

The ARC Board of Directors will consist of 11 members, comprised of six directors from ARC and five directors from Seven Generations. ARC's Chair of the Board of Directors, Hal Kvisle, will remain as independent Chair of the Board of Directors and Seven Generations' President and Chief Executive Officer, Marty Proctor, will join the Board of Directors to serve as Vice-Chair. Management will be led by ARC's Terry Anderson as President and Chief Executive Officer, ARC's Kris Bibby as Senior Vice President and Chief Financial Officer, and Seven Generations' David Holt as Senior Vice President and Chief Operating Officer. Additional senior leaders for the combined company will be selected from the senior leadership teams at both organizations and will be named prior to the close of the transaction.

Under the terms of the Business Combination Agreement, Seven Generations shareholders will receive 1.108 common shares of ARC for each Seven Generation share held. Following closing of the transaction, ARC shareholders will own approximately 49 per cent and Seven Generations shareholders will own approximately 51 per cent of the total shares outstanding. The transaction is structured through a plan of arrangement in respect of the securities of Seven Generations under the *Canada Business Corporations Act*, and is subject to shareholder approval for both ARC and Seven Generations, regulatory approvals, and other customary closing conditions. The transaction is expected to close in the second quarter of 2021.

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, 2020. 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 29, 2021. The reserves data summarizes our reserves and the net present values of future net revenues for these reserves, using forecast prices and costs prior to provision for interest, general and administrative expenses, and the impact of any financial hedging activities. Reserves evaluation includes abandonment and reclamation costs for all active and inactive wells, facilities, and pipelines within all properties with or without attributable 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 Crude 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 Crude 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, 2021 news release entitled, *"ARC Resources Ltd. Reports Fourth Quarter and Year-end 2020 Financial and Operational Results and 2020 Reserves Results"* available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

Summary of 2020 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 Crude Oil (Mbbl)	NGLs (Mbbl)(1)(2)	Total Crude Oil and NGLs (Mbbl)	Conventional Natural Gas (Bcf)	Shale Gas (Bcf)	Total Gas (Bcf)	Total Oil Equivalent (Mboe)
PROVED									
Developed Producing	24,009	507	10,984	31,828	67,328	34.5	1,169.5	1,204.0	267,991
Developed Non-Producing	3,046	—	55	2,588	5,689	2.8	66.8	69.6	17,284
Undeveloped	5,349	—	8,499	49,693	63,541	11.0	1,515.2	1,526.2	317,910
TOTAL PROVED	**32,404**	**507**	**19,538**	**84,110**	**136,558**	**48.3**	**2,751.5**	**2,799.8**	**603,185**
PROBABLE	9,607	172	12,896	53,427	76,102	17.1	1,481.1	1,498.2	325,798
TOTAL PROVED PLUS PROBABLE	**42,011**	**679**	**32,434**	**137,536**	**212,660**	**65.4**	**4,232.6**	**4,297.9**	**928,984**

Company Net Reserves	Light Crude Oil and Medium Crude Oil (Mbbl)	Heavy Crude Oil (Mbbl)	Tight Crude Oil (Mbbl)	NGLs (Mbbl)(1)(2)	Total Crude Oil and NGLs (Mbbl)	Conventional Natural Gas (Bcf)	Shale Gas (Bcf)	Total Gas (Bcf)	Total Oil Equivalent (Mboe)
PROVED									
Developed Producing	22,753	813	9,929	27,541	61,036	32.4	1,098.1	1,130.5	249,459
Developed Non-Producing	2,884	—	54	2,282	5,220	2.6	61.6	64.3	15,932
Undeveloped	5,025	—	7,351	45,467	57,844	10.4	1,472.3	1,482.7	304,957
TOTAL PROVED	**30,662**	**813**	**17,335**	**75,291**	**124,100**	**45.5**	**2,632.0**	**2,677.5**	**570,348**
PROBABLE	8,631	270	10,802	45,214	64,918	16.3	1,398.0	1,414.3	300,640
TOTAL PROVED PLUS PROBABLE	**39,293**	**1,083**	**28,136**	**120,505**	**189,018**	**61.8**	**4,030.0**	**4,091.8**	**870,988**

1) NGLs includes associated NGLs for both Conventional and Shale/Tight Reservoirs, and includes condensate, propane, and butane.
2) Condensate and Pentanes Plus represent 52 per cent of Proved Developed Producing NGLs and 61 per cent of NGLs in the Total Proved and Total Proved Plus Probable categories.

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	2,234	2,165	1,914	1,700	1,531
Developed Non-Producing	273	205	160	131	112
Undeveloped	2,749	1,764	1,173	804	564
TOTAL PROVED	**5,256**	**4,134**	**3,248**	**2,636**	**2,206**
PROBABLE	4,390	2,529	1,626	1,140	851
TOTAL PROVED PLUS PROBABLE	**9,646**	**6,663**	**4,874**	**3,776**	**3,057**
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	1,901	1,899	1,693	1,510	1,364
Developed Non-Producing	205	154	119	97	82
Undeveloped	2,024	1,250	788	502	319
TOTAL PROVED	**4,129**	**3,303**	**2,600**	**2,109**	**1,765**
PROBABLE	3,275	1,865	1,183	819	604
TOTAL PROVED PLUS PROBABLE	**7,403**	**5,168**	**3,783**	**2,928**	**2,369**

1) Reflects estimated abandonment and reclamation for all active and inactive areas including all wells (both existing and undrilled), facilities and pipelines, including those areas with no attributed reserves.
2) Based on ARC's estimated tax pools at year-end 2020.
3) The after-tax net present value of ARC's crude oil and natural gas assets presented here reflect the income tax burden on the assets on a stand-alone basis. It does not consider the businessentity-level tax situation, or tax planning. It does not provide an estimate of the net present value at the level of the business entity, which may be significantly different. 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	14,375	932	5,000	2,347	840	5,256	1,127	4,129
Proved Plus Probable Reserves	23,209	1,825	7,616	3,185	936	9,646	2,243	7,403

1) Reflects estimated abandonment and reclamation for all active and inactive areas including all wells (both existing and undrilled), facilities and pipelines, including those areas with no 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]	181	$5.90/bbl
	Heavy Crude Oil [2][3]	20	$24.83/bbl
	Tight Crude Oil [2]	451	$26.01/bbl
	Conventional Natural Gas [4]	1	$0.10/Mcf
	Shale Gas [4]	2,595	$1.06/Mcf
	Total	**3,248**	**$5.69/boe**
Proved Plus Probable Reserves	Light Crude Oil and Medium Crude Oil [2]	282	$7.17/bbl
	Heavy Crude Oil [2][3]	24	$22.43/bbl
	Tight Crude Oil [2]	758	$26.94/bbl
	Conventional Natural Gas [4]	1	$0.15/Mcf
	Shale Gas [4]	3,809	$1.03/Mcf
	Total	**4,874**	**$5.60/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

These 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 shall be incorporated into the forecast prices.

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, 2021 price forecasts and exchange rates as follows:

Summary of GLJ January 1, 2021 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$)
2021	48.00	55.49	39.52	53.82	2.75	2.72	19.43	27.75	60.65	—	0.775
2022	51.50	60.78	43.97	58.96	2.80	2.67	24.31	36.47	65.36	1.0	0.765
2023	54.50	63.82	48.11	61.90	2.85	2.60	25.53	41.48	70.07	2.0	0.760
2024	57.79	68.14	51.88	66.10	2.90	2.60	27.26	44.29	74.72	2.0	0.760
2025	58.95	69.67	52.94	67.58	2.95	2.65	27.87	45.29	76.25	2.0	0.760
2026	60.13	71.22	54.00	69.09	3.01	2.71	28.49	46.30	77.80	2.0	0.760
2027	61.33	72.80	55.10	70.62	3.07	2.76	29.12	47.32	79.38	2.0	0.760
2028	62.56	74.42	56.22	72.19	3.13	2.81	29.77	48.37	81.00	2.0	0.760
2029	63.81	76.07	57.35	73.78	3.19	2.87	30.43	49.44	82.64	2.0	0.760
2030	65.09	77.59	58.50	75.26	3.25	2.92	31.03	50.43	84.30	2.0	0.760
Thereafter	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	(4)	2.0	0.780

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, 2020.
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 2031.

ARC's weighted average realized prices, prior to hedging, for the year ended December 31, 2020, were $2.26 per Mcf for shale gas and conventional natural gas, $42.94 per barrel for tight crude oil, light crude oil and medium crude oil, $24.10 per barrel for heavy crude oil, $47.62 per barrel for condensate, and $12.69 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, 2020, using forecast price and cost estimates derived from the GLJ Report. Gross reserves as at December 31, 2020 and as at December 31, 2019 include working interest reserves before royalties payable and without including gross royalties receivable. Key highlights include:

- Continued strong well performance across ARC's Montney assets, driving positive technical revisions in the Shale Gas category.
- Strong well performance in the Dawson area resulted in extensions and improved recovery that offset negative technical revisions in the NGLs probable category by greater than 12 times. The minor technical revisions were the result of ARC refining its expectations for ultimate NGLs recovery.
- Strong NGLs production from lower Montney development at Parkland/Tower offset negative technical revisions in the Tight Oil category, which were primarily attributed to recent well results from development activities targeting the upper Montney horizon at Tower.
- ARC divested 44 MMboe of proved plus probable reserves in 2020, of which 97 per cent was attributed to an asset exchange transaction involving lands in northeast British Columbia.
- Economic factors, which primarily affected ARC's Pembina area, had a minor impact to total reserves. Less than one per cent of total proved and proved plus probable volumes were removed due to the negative impact of lower 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 Crude Oil (Mbbl)	NGLs (Mbbl)(1)(2)(3)	Total Crude Oil and NGLs (Mbbl)	Conventional Natural Gas (Bcf)	Shale Gas (Bcf)	Total Gas (Bcf)	Total Oil Equivalent (Mboe)
PROVED									
December 31, 2019	**35,849**	**526**	**21,526**	**86,057**	**143,958**	**53.1**	**2,655.3**	**2,708.4**	**595,363**
Extensions and Improved Recovery (4)	—	—	2,112	7,074	9,185	—	299.5	299.5	59,108
Technical Revisions	1,126	11	(30)	521	1,628	6.2	164.7	170.9	30,109
Dispositions	(522)	—	—	(585)	(1,107)	(2.7)	(99.7)	(102.4)	(18,178)
Economic Factors	(1,768)	—	(694)	(677)	(3,139)	(3.5)	(2.8)	(6.2)	(4,180)
Production (5)	(2,281)	(30)	(3,375)	(8,281)	(13,967)	(4.9)	(265.6)	(270.4)	(59,036)
December 31, 2020	**32,404**	**507**	**19,538**	**84,110**	**136,558**	**48.3**	**2,751.5**	**2,799.8**	**603,185**
PROBABLE									
December 31, 2019	**10,177**	**179**	**14,518**	**47,781**	**72,655**	**18.8**	**1,432.7**	**1,451.5**	**314,567**
Extensions and Improved Recovery (4)	—	—	104	8,456	8,560	—	224.8	224.8	46,033
Technical Revisions	(203)	(7)	(1,460)	(1,726)	(3,395)	(0.1)	(39.3)	(39.4)	(9,960)
Acquisitions	—	—	—	2	2	—	16.7	16.7	2,788
Dispositions	(126)	—	—	(785)	(912)	(0.7)	(151.2)	(151.9)	(26,228)
Economic Factors	(240)	—	(267)	(301)	(808)	(0.8)	(2.8)	(3.6)	(1,403)
December 31, 2020	**9,607**	**172**	**12,896**	**53,427**	**76,102**	**17.1**	**1,481.1**	**1,498.2**	**325,798**
PROVED PLUS PROBABLE									
December 31, 2019	**46,026**	**705**	**36,044**	**133,838**	**216,613**	**71.9**	**4,088.0**	**4,159.9**	**909,930**
Extensions and Improved Recovery (4)	—	—	2,216	15,530	17,746	—	524.4	524.4	105,141
Technical Revisions	923	4	(1,490)	(1,205)	(1,768)	6.1	125.4	131.5	20,150
Acquisitions	—	—	—	2	2	—	16.7	16.7	2,788
Dispositions	(648)	—	—	(1,370)	(2,018)	(3.4)	(250.9)	(254.3)	(44,406)
Economic Factors	(2,008)	—	(961)	(978)	(3,947)	(4.3)	(5.5)	(9.8)	(5,583)
Production (5)	(2,281)	(30)	(3,375)	(8,281)	(13,967)	(4.9)	(265.6)	(270.4)	(59,036)
December 31, 2020	**42,011**	**679**	**32,434**	**137,536**	**212,660**	**65.4**	**4,232.6**	**4,297.9**	**928,984**

1) NGLs includes associated NGLs for both Conventional and Shale/Tight Reservoirs.
2) Condensate and Pentanes Plus represent 62 per cent of Total Proved NGLs and 63 per cent of Probable and Proved Plus Probable NGLs in the December 31, 2019 opening balance.
3) Condensate and Pentanes Plus represent 60 per cent of Total Proved NGLs and 61 per cent of Probable and Proved Plus Probable NGLs in the December 31, 2020 closing balance.
4) Reserve additions for 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 attributable to the reserves categories noted below:

Future Development Costs

Year	Proved Reserves ($ millions)	Proved Plus Probable Reserves ($ millions)
2021	369	382
2022	277	310
2023	278	396
2024	433	482
2025	374	518
Remainder	615	1,098
Total: Undiscounted	2,347	3,185
Total: Discounted at 10% per Year	1,692	2,191

We expect to fund the development costs of the reserves through a combination of sources including funds from operations[1] and debt.

Changes in forecast 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 decreased $194 million compared to year-end 2019, to total $3.2 billion at year-end 2020. The decrease in FDC was driven by the completion of the Dawson Phase IV gas processing and liquids-handling facility, which was brought on-stream in the second quarter of 2020, as well as capital efficiency improvements related to recent drilling and completions activities.

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.

(1) For information on funds from operations refer to Note 16 "*Capital Management*" in the financial statements and to the sections entitled "*Funds from Operations*" and "*Capitalization, Financial Resources and Liquidity*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

Proved Undeveloped Reserves

	Light Crude Oil and Medium Crude Oil (Mbbl)		Tight Crude 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
2018	—	6,198	2,373	14,302	—	12.1	278.6	1,389.4
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

	NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2018	12,956	40,593	61,770	294,677
2019	8,236	54,529	44,810	323,196
2020	14,114	49,694	58,415	317,910

Probable Undeveloped Reserves

	Light Crude Oil and Medium Crude Oil (Mbbl)		Tight Crude 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
2018	—	3,082	2,637	13,766	—	6.9	265.8	1,224.5
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

	NGLs (Mbbl)		Total (Mboe)	
	First Attributed	Total at Year-end	First Attributed	Total at Year-end
2018	8,607	32,221	55,537	254,298
2019	4,468	37,427	16,717	236,007
2020	14,305	40,796	53,225	236,815

As of December 31, 2020, undeveloped reserves represented 53 per cent of total proved reserves and 60 per cent of proved plus probable reserves. Over 98 per cent of the proved plus probable undeveloped reserves are located in our Montney assets of northeast British Columbia and northern Alberta. We have planned a program for the development of a portion of the undeveloped reserves in 2021 and 2022, focusing on the Dawson, Parkland/Tower, 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 451 total proved, undeveloped locations assigned to be developed in ARC's core properties over the next seven to nine years in the 2020 evaluation which account for 318 MMboe of reserves volumes. Additional to these total proved undeveloped locations are 154 future development locations assigned probable reserves only, an incremental 34 per cent, which extended the timeline to develop these reserves over the next seven to 10 years. These probable locations and additional probable reserves assigned to proved locations account for 237 MMboe. The total proved plus probable undeveloped volumes account for 555 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 2021 and 2022, as well as in years beyond 2022, 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 would also 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 following table sets forth information respecting anticipated future abandonment and reclamation costs for surface leases, wells, facilities, and pipelines, as well as those with no reserves attributed (aggregated at a property level)**:**

Abandonment & Reclamation Costs Escalated at 2.0%	**Undiscounted ($ millions)**	**Discounted at 10% [1] ($ millions)**
Total as at December 31, 2020	870.1	84.6
Anticipated to be paid in 2021	19.0	17.3
Anticipated to be paid in 2022	25.0	20.7
Anticipated to be paid in 2023	25.0	18.8

(1) Costs have been discounted in the financial statements at a liability-specific risk-free rate of 1.21 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 Attributable 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 crude oil and natural gas property, plant and equipment ("PP&E") and exploration and evaluation assets 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[1]. 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, third-party engineering firms, and actual 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.

(1) For information on funds from operations refer to Note 16 "*Capital Management*" in the financial statements and to the sections entitled "*Funds from Operations*" and "*Capitalization, Financial Resources and Liquidity*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

As at December 31, 2020, ARC had 3,373 net wells for which we expect to incur abandonment and reclamation costs. In estimating the future net revenues disclosed in this Annual Information Form, the GLJ Report, in the Proved plus Probable category, deducted $936.0 million (undiscounted) and $123.8 million (discounted at 10 per cent) for abandonment and reclamation costs for all wells (both existing and undrilled wells) as well as properties with no attributed reserves.

Additional information related to our reclamation and abandonment obligations can be found in Note 15 "*Asset Retirement Obligation*" in the financial statements and in the section entitled "*Asset Retirement Obligation*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

CORE OPERATING AREAS

The following is a description of ARC's principal crude oil and natural gas properties as at December 31, 2020. Information in respect of gross and net acres and well counts are as at December 31, 2020. Due to the fact that ARC has been active at 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, 2020 may not directly correspond to the stated production for the year, which only includes production after (or up to) the date the interests were acquired (or divested) by ARC.

ARC's crude oil and natural gas properties described below are all located in the Western Canadian Sedimentary Basin and onshore within the Canadian provinces of 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, 2020, 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.

British Columbia

Northeast 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 96 per cent in approximately 246,577 gross hectares (237,645 net hectares), which includes land holdings of 661 net Montney sections. ARC drilled 45 gross operated wells in 2020 within the region, with an average working interest of 100 per cent. ARC owns and operates approximately 716 MMcf per day of natural gas and 31,000 barrels per day of liquids processing capacity through its facilities in the region.

Alberta

Northern Alberta

ARC has an average working interest of 85 per cent in the area with approximately 126,666 gross hectares (107,499 net hectares), which includes land holdings of 308 net Montney sections. ARC drilled 14 gross operated wells in 2020 within the northern Alberta region, with an average working interest of 100 per cent.

Pembina

ARC has an average working interest of 80 per cent in approximately 76,281 gross hectares (61,058 net hectares).

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, 2020.

By Province	Crude Oil Wells [1]				Natural Gas Wells [2]			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
British Columbia	118	117	10	9	475	460	198	181
Alberta	1,194	955	882	613	102	46	139	76
Total [3]	1,312	1,072	892	622	577	506	337	257

1) Includes Light Crude Oil and Medium Crude Oil wells, Heavy Crude Oil, wells and Tight Crude 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 ATTRIBUTABLE RESERVES

The following table sets out by province our properties with no attributed reserves as at December 31, 2020.

Undeveloped Hectares

	Gross	Net
British Columbia	167,888	164,127
Alberta	94,571	56,233
Total	262,459	220,360

Unproved 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 2021. There are no material expiries in our core holdings in 2021.

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[1] 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.

(1) For information on funds from operations refer to Note 16 "*Capital Management*" in the financial statements and to the sections entitled "*Funds from Operations*" and "*Capitalization, Financial Resources and Liquidity*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

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

A part of our ongoing strategy is to secure transportation capacity to ensure our production moves to market over the short and long term. ARC believes that securing firm takeaway capacity is prudent management of our business, and has secured sufficient takeaway for 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)	179	96
Crude Oil and NGLs (Mbbl/d)	—	—
Estimated Cost ($ millions)	102	279

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 65 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)	150	89
Crude Oil and NGLs (Mbbl/d)	—	—
Estimated Cost ($ millions)	89	262

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 opportunities where it may reduce its exposure to negative cash flows arising from the settlements of these contract obligations.

Additional disclosure related to such commitments, as well as ARC's other financial contracts as at December 31, 2020, are set forth in Note 22 *"Commitments and Contingencies"* in the financial statements, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

TAX HORIZON

We expect to allocate our funds from operations[(1)] towards a portion of capital expenditures, periodic debt repayments, site reclamation expenditures, potential net acquisitions of undeveloped land and production, and cash payments to shareholders in the form of dividends. Taxable income varies depending on total income and expenses and varies with changes to commodity prices, costs, claims for both accumulated tax pools, and tax pools associated with current year expenditures, acquisitions, and dispositions.

ARC has accumulated $1.5 billion of income tax pools for federal tax purposes as at December 31, 2020. In 2020, ARC recognized a current income tax recovery of $26.8 million. For 2021, ARC expects current income tax expense to range from three per cent to seven per cent of funds from operations[(1)]; however, this will be dependent on the commodity price environment and the amount of capital invested. For more information, please see Note 18 *"Income Taxes"* in the financial statements, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

(1) For information on funds from operations refer to Note 16 "*Capital Management*" in the financial statements and to the sections entitled "*Funds from Operations*" and "*Capitalization, Financial Resources and Liquidity*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

CAPITAL EXPENDITURES

The following table summarizes capital expenditures (net of incentives and net of certain acquisitions and dispositions, and including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2020:

2020 Capital and Land Expenditures

($ millions)	British Columbia	Alberta	Total
Property Acquisition (Disposition) Costs, Net [1]			
Proved Properties	(0.1)	(1.7)	(1.8)
Undeveloped Properties	0.2	—	0.2
Exploration Costs [2]	(6.1)	—	(6.1)
Development Costs [3]	270.6	67.3	337.9
Capitalized Corporate Costs [4]	—	11.4	11.4
Total	**264.6**	**77.0**	**341.6**

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 exploration and evaluation stage and includes costs of land acquired ($nil).
3) Represents additions to PP&E and includes costs of land acquired ($nil).
4) Includes capitalized overhead and other corporate assets.

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, 2020.

By Well Type	Development Wells [1]		Total [1][2]	
	Gross	Net	Gross	Net
Crude Oil	14	14.00	14	14.00
Natural Gas	45	45.00	45	45.00
Total	**59**	**59.00**	**59**	**59.00**

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, 2020.

PRODUCTION ESTIMATES

The following tables set out the GLJ forecast of the volume of production estimated for the year ended December 31, 2021 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 Crude 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
Dawson	—	—	—	—	—	—	—	—	306,386	293,010	10,488	9,793	61,552	58,628
Sunrise	—	—	—	—	—	—	—	—	234,231	226,698	24	20	39,063	37,803
Other Properties	5,312	5,123	76	226	7,521	6,814	10,840	10,047	172,600	161,192	11,298	9,876	54,782	50,578
Total Proved	**5,312**	**5,123**	**76**	**226**	**7,521**	**6,814**	**10,840**	**10,047**	**713,217**	**680,900**	**21,810**	**19,689**	**155,397**	**147,009**

TOTAL PROBABLE	Light Crude Oil & Medium Crude Oil (bbl/d)		Heavy Crude Oil (bbl/d)		Tight Crude 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
Dawson	—	—	—	—	—	—	—	—	15,284	14,915	769	731	3,316	3,217
Sunrise	—	—	—	—	—	—	—	—	8,106	7,865	1	1	1,352	1,312
Other Properties	103	90	1	8	671	584	274	261	13,005	12,361	1,282	1,169	4,269	3,954
Total Probable	**103**	**90**	**1**	**8**	**671**	**584**	**274**	**261**	**36,395**	**35,142**	**2,051**	**1,901**	**8,937**	**8,483**

TOTAL PROVED PLUS PROBABLE	Light Crude Oil & Medium Crude Oil (bbl/d)		Heavy Crude Oil (bbl/d)		Tight Crude 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
Dawson	—	—	—	—	—	—	—	—	321,670	307,926	11,256	10,523	64,868	61,844
Sunrise	—	—	—	—	—	—	—	—	242,337	234,563	25	21	40,414	39,115
Other Properties	5,415	5,213	77	234	8,192	7,397	11,114	10,308	185,606	173,553	12,580	11,045	59,051	54,533
Total Proved Plus Probable	**5,415**	**5,213**	**77**	**234**	**8,192**	**7,397**	**11,114**	**10,308**	**749,612**	**716,042**	**23,861**	**21,590**	**164,334**	**155,492**

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 resulting netback for the periods indicated below:

Production History	**Three Months Ended 2020**				**Year Ended**
	March 31	**June 30**	**September 30**	**December 31**	**2020**
Average Daily Production [(1)]					
Light and Medium Crude Oil (bbl/d)	7,580	6,482	5,459	5,502	6,251
Heavy Crude Oil (bbl/d)	378	54	357	236	256
Tight Crude Oil (bbl/d)	9,039	8,451	9,557	9,816	9,219
Conventional Natural Gas (MMcf/d)	12.3	11.9	11.1	10.6	11.5
Shale Gas (MMcf/d)	679.9	761.4	697.1	772.5	727.7
NGLs (bbl/d) [(2)]	19,414	22,644	25,039	23,393	22,631
Condensate (bbl/d)	11,262	13,239	14,831	14,715	13,519
Other NGLs (bbl/d) [(3)]	8,152	9,405	10,208	8,678	9,112
Total (boe/d)	151,783	166,510	158,444	169,468	161,564
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	51.19	26.54	44.76	49.31	43.01
Heavy Crude Oil ($/bbl)	14.89	14.23	30.45	31.36	24.10
Tight Crude Oil ($/bbl)	49.88	25.44	46.41	47.89	42.87
Conventional Natural Gas ($/Mcf)	2.09	1.92	2.16	2.83	2.24
Shale Gas ($/Mcf)	2.05	1.92	2.16	2.88	2.26
NGLs ($/bbl) [(2)]	36.04	22.94	34.78	40.38	33.56
Condensate ($/bbl)	57.52	31.54	48.49	53.55	47.62
Other NGLs ($/bbl) [(3)]	6.36	10.84	14.85	18.03	12.69
Total ($/boe)	19.52	14.38	19.55	23.29	19.20

Production History - continued	Three Months Ended 2020				Year Ended
	March 31	June 30	September 30	December 31	2020
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	3.60	0.96	1.84	1.90	2.16
Heavy Crude Oil ($/bbl)	0.07	(0.59)	0.15	0.18	0.09
Tight Crude Oil ($/bbl)	6.14	1.27	2.77	3.22	3.37
Conventional Natural Gas ($/Mcf)	(0.28)	(0.27)	(0.12)	(0.12)	(0.20)
Shale Gas ($/Mcf)	0.03	0.02	0.02	0.08	0.04
NGLs ($/bbl) (2)	3.51	1.33	2.51	3.18	2.60
Condensate ($/bbl)	5.67	1.70	3.29	3.96	3.58
Other NGLs ($/bbl) (3)	0.53	0.81	1.38	1.84	1.15
Total ($/boe)	1.11	0.38	0.72	1.04	0.81
Operating Expense (4)(5)					
Light and Medium Crude Oil ($/bbl)	19.88	13.91	22.19	25.91	20.24
Heavy Crude Oil ($/bbl)	7.17	25.25	1.29	4.21	5.38
Tight Crude Oil ($/bbl)	5.50	3.30	4.84	4.68	4.62
Conventional Natural Gas ($/Mcf)	3.67	4.42	5.84	5.37	4.99
Shale Gas ($/Mcf)	0.49	0.39	0.45	0.41	0.43
NGLs ($/bbl) (2)	4.63	3.56	4.35	4.69	4.16
Condensate ($/bbl)	4.58	3.73	4.39	4.13	4.18
Other NGLs ($/bbl) (3)	4.71	3.33	4.30	5.64	4.14
Total ($/boe)	4.40	3.32	4.13	3.97	3.94
Transportation Expense					
Light and Medium Crude Oil ($/bbl)	1.68	1.78	1.74	1.67	1.72
Heavy Crude Oil ($/bbl)	0.07	0.04	0.01	0.03	0.04
Tight Crude Oil ($/bbl)	3.55	3.64	3.10	3.37	3.41
Conventional Natural Gas ($/Mcf)	0.42	0.48	0.41	0.41	0.43
Shale Gas ($/Mcf)	0.41	0.40	0.48	0.44	0.43
NGLs ($/bbl) (2)	5.48	5.52	5.29	5.10	5.34
Condensate ($/bbl)	6.06	5.65	5.50	5.19	5.57
Other NGLs ($/bbl) (3)	4.66	5.34	4.97	4.94	4.99
Total ($/boe)	2.85	2.88	3.22	2.97	2.98
Netback Received (6)					
Light and Medium Crude Oil ($/bbl)	26.03	9.89	18.99	19.83	18.89
Heavy Crude Oil ($/bbl)	7.58	(10.47)	29.00	26.94	18.59
Tight Crude Oil ($/bbl)	34.69	17.23	35.70	36.62	31.47
Conventional Natural Gas ($/Mcf)	(1.72)	(2.71)	(3.97)	(2.83)	(2.98)
Shale Gas ($/Mcf)	1.12	1.11	1.21	1.95	1.36
NGLs ($/bbl) (2)	22.42	12.53	22.63	27.41	21.46
Condensate ($/bbl)	41.21	20.46	35.31	40.27	34.29
Other NGLs ($/bbl) (3)	(3.54)	1.36	4.20	5.61	2.41
Total ($/boe)	11.16	7.80	11.48	15.31	11.47

1) Before deduction of royalties and including royalty interests.
2) NGLs as defined by GLJ which includes condensate, butane, ethane, and propane.
3) Other NGLs as defined by ARC includes butane, ethane, and propane but excludes condensate.
4) Operating expense is comprised of direct costs incurred to operate both crude oil and natural gas wells. A number of assumptions have been made in allocating these costs between crude oil, natural gas, condensate, and NGLs production.
5) Operating recoveries associated with operated properties were excluded from operating expense and accounted for as a reduction to general and administrative costs.
6) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled *"Non-GAAP Measures"* contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

British Columbia and Alberta account for approximately 84 per cent and 16 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, please see Note 22 "*Commitments and Contingencies*" in the financial statements, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

Natural Gas

During 2020, 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.

The average natural gas price we received during 2020 was $2.26 per Mcf before hedging as compared to $2.12 per Mcf before hedging for 2019. This price was achieved with a portfolio mix that on average through the year, before hedging, received AECO index-based pricing for 38 per cent, US Midwest index-based pricing for 27 per cent, Station 2 index-based pricing for 20 per cent, Pacific Northwest index-based pricing for nine per cent, and Dawn index-based pricing for six 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 2020 comprised approximately 33 per cent light crude oil (greater than 35° API), 11 per cent medium crude oil (25° to 35° API), one per cent heavy crude oil (less than 25° API), and 55 per cent condensate and other NGLs.

During 2020, our average sales prices before hedging were $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; these prices compare to 2019 prices of $66.07 per barrel for light and medium crude oil, $59.72 per barrel for heavy crude oil, and $43.85 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 ensure an optimal netback(1).

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled *"Non-GAAP Measures"* contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

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 353,371,731 common shares and no preferred shares were outstanding as at December 31, 2020.

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.

OTHER INFORMATION RELATING TO OUR BUSINESS

BORROWING

ARC borrows funds periodically to finance the purchase of assets, for capital expenditures, 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 annualized funds from operations[(1)] between 1.0 to 1.5 times. The level of borrowing is assessed on a weekly basis by Management and is subject to quarterly reviews by the Board of Directors of ARC Resources.

Our borrowings may comprise both a bank credit facility and long-term notes issued to major financial institutions. 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, 2020, we had credit facilities consisting of a $950.0 million, financial covenant-based 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 US$469.0 million and $32.0 million of senior notes outstanding. ARC had a net debt[(1)] balance of $742.7 million outstanding at December 31, 2020, comprised of $701.9 million of long-term debt, $49.2 million of lease obligations, and a working capital surplus of $8.4 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 December 15, 2023.

The senior notes outstanding were issued in six tranches and bear interest at a fixed rate. Each tranche requires certain repayments of principal prior to the final maturity thereof. During the year ended December 31, 2020, ARC executed certain amendments to the note purchase agreements governing its senior notes. The amendments were effective March 31, 2020 and included a modification of certain definitions contained within the financial covenant calculations, the addition of a minimum liquidity requirement, additional language surrounding event of default, and the addition of a mechanism under which the issuer may offer to purchase notes outstanding at par without penalty. As well, the definition of "Total EBITDA" to be used in determining compliance under two of ARC's financial covenants was amended to exclude non-cash losses and non-cash expenses.

The following are financial covenants governing the credit facilities and the Master Shelf Agreement dated March 13, 2019. Capitalized terms are as defined in the credit facility agreement and the Master Shelf Agreement:

- Consolidated Senior Debt not to exceed 3.5 times Consolidated EBITDA;
- Consolidated Total Senior Debt not to exceed 4.0 times Consolidated EBITDA;
- Consolidated Senior Debt not to exceed 55 per cent of Total Capitalization; and
- Consolidated Tangible Assets of the Restricted Group must exceed 85 per cent of Consolidated Tangible Assets.

The following are financial covenants related to the outstanding senior notes. Capitalized terms are as defined in the note purchase agreements:

- Total Indebtedness not to exceed 325 per cent total EBITDA for the most recently completed period of four consecutive quarters;
- Total EBITDA not to be less than 400 per cent of Total Interest Charges for the most recently completed period of four consecutive quarters;
- Total Priority Indebtedness not to exceed two per cent of Total Assets; and
- Total Indebtedness not to exceed 65 per cent of Present Asset Value.

(1) For information on net debt and net debt to annualized funds from operations refer to Note 16 "*Capital Management*" in the financial statements and to the sections entitled "*Funds from Operations*" and "*Capitalization, Financial Resources and Liquidity*" contained within the MD&A, available on ARC's website at www.arcresources.com and on SEDAR at www.sedar.com.

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. The syndicated credit agreement, the note agreements, and master shelf agreement are described in this Annual Information Form under "*Material Contracts*" and are available on SEDAR at www.sedar.com. For more information, refer to Note 14 "*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.

As of December 31, 2020, ARC did not have credit ratings or other ratings concerning ARC or any of its securities.

On March 1, 2021, DBRS Limited (DBRS Morningstar) ("DBRS") assigned a provisional issuer rating of BBB Stable to ARC and a provisional rating of BBB Stable to the up to $1.0 billion senior unsecured notes that ARC plans to issue in connection with the Business Combination (the "New ARC Notes"), in each case, assuming completion of the Business Combination and other assumptions.

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.

DBRS has assigned ARC (on a pro forma basis assuming completion of the Business Combination) a BBB issuer rating (stable trend), which is the fourth highest of ten categories for long-term debt.

DBRS has also assigned the New ARC Notes (on a pro forma basis assuming completion of the Business Combination) a BBB rating (stable trend). In DBRS' view, a BBB rating has adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but the entity may be vulnerable to future events.

Payments to Credit Rating Organizations

ARC has made payments to, and reasonably expects, from time to time, to continue to make customary payments to the credit rating organizations set forth above for the provision of the related ratings and other services.

CORPORATE SOCIAL RESPONSIBILITY

ARC is committed to operating in a responsible manner and integrating principles of responsible development into all parts of our business. Our Corporate Code of Conduct, Environmental, and Health and Safety Policies guide our activities in these areas. These policies are available on our website at www.arcresources.com.

We published our most recent biennial environment, social, and governance ("ESG") Report in August 2020 detailing our efforts and performance in environmental management, health and safety, leadership culture, community investment, stakeholder engagement, and corporate governance. ARC's 2020 ESG Report is aligned with the Sustainability Accounting Standards Board's "*Extractives & Minerals Processing Sector: Oil and Gas - Exploration & Production Sustainability Accounting Standard"* framework and includes climate change disclosure which aligns with recommendations of the Task Force on Climate-related Financial Disclosures. ARC strives to deliver industry-leading performance in all aspects of its business. ARC has built a culture that fosters responsible resource development to deliver strong financial and operational results by prioritizing environmental and social responsibility efforts. Strong governance practices and ongoing commitment from employees is critical. The report can be viewed at www.arcresources.com/responsibility/sustainability-reports.

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 December 31, 2020 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. Prior to May 2015, he was President and Chief Executive Officer of Talisman Energy.
Farhad Ahrabi Houston, Texas, USA	2019 Independent	Mr. Ahrabi is the Chief Executive Officer of Cameron LNG.
David R. Collyer Calgary, Alberta, Canada	2016 Independent	Mr. Collyer is an independent business person.
John P. Dielwart Calgary, Alberta, Canada	1996 Independent	Mr. Dielwart is currently the Vice-Chairman of ARC Financial Corporation.
Michael G. McAllister Calgary, Alberta, Canada	2020 Independent	Mr. McAllister is an independent business person. Prior to May 2020, Mr. McAllister held the positions of President and Chief Operating Officer at Ovintiv Inc. (formerly Encana Corporation).
Kathleen M. O'Neill Toronto, Ontario, Canada	2009 Independent	Ms. O'Neill is an independent business person.
Herbert C. Pinder, Jr. Saskatoon, Saskatchewan, Canada	2006 Independent	Mr. Pinder is an independent business person.
William G. Sembo Calgary, Alberta, Canada	2013 Independent	Mr. Sembo is an independent business person and acts as advisor for Lazard Canada Inc.
Nancy L. Smith [(2)] Calgary, Alberta, Canada	2016 Independent	Ms. Smith is a Director and Investment Committee Member of ARC Financial Corporation.
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.
2) Ms. Smith was a director of Corinthian Oil Corp. ("Corinthian") until September 19, 2017 when it was acquired by a third party. Corinthian was solvent, had positive working capital and no long-term debt while Ms. Smith was a director. Ms. Smith resigned her directorship on closing of the transaction. Corinthian was later amalgamated with a wholly-owned subsidiary of the third party and the amalgamated subsidiary subsequently guaranteed debt of the third party purchaser. In the following year, the third party filed a notice of intention under the *Bankruptcy and Insolvency Act* (which ultimately included its subsidiaries as a result of the guarantees provided by the subsidiaries) pursuant to which a receiver and manager of its assets was appointed under a court order and the third party and its subsidiaries were declared bankrupt.

As at December 31, 2020, the Directors and officers of ARC Resources, as a group, beneficially owned, or controlled or directed, directly or indirectly, 5,840,412 common shares or approximately 1.65 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 December 31, 2020 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.
Sean R. A. Calder Calgary, Alberta, Canada	**Vice President, Production** Mr. Calder is the Vice President, Production.
Larissa M. Conrad Calgary, Alberta, Canada	**Vice President, Development and Planning** Ms. Conrad is the Vice President, Development and Planning. Prior to December 2019, she was the Vice President, Engineering and Planning.
Christopher D. Baldwin Calgary, Alberta, Canada	**Vice President, Geosciences** Mr. Baldwin is the Vice President Geosciences. Prior to January 2017, he was the Manager, Geosciences North.
Ryan V. Berrett Calgary, Alberta, Canada	**Vice President, Marketing** Mr. Berrett is the Vice President, Marketing. Prior to January 2017, he was the Manager, Marketing.
Armin Jahangiri Calgary, Alberta, Canada	**Vice President, Operations** Mr. Jahangiri is the Vice President, Operations. Prior to March 2017, he was the Manager, Engineering North.
Lisa A. Olsen Calgary, Alberta, Canada	**Vice President, Human Resources** Ms. Olsen is the Vice President, Human Resources. Prior to January 2016, she was the Manager, Human Resources.
Grant A. Zawalsky (1) Calgary, Alberta, Canada	**Corporate Secretary** Mr. Zawalsky is the Managing Partner at Burnet, Duckworth & Palmer LLP (law firm).

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

MEMBERSHIP OF BOARD COMMITTEES

The following chart sets out the membership of the committees of the Board of Directors as at March 1, 2021.

Name of Director	Audit	Human Resources & Compensation	Policy & Board Governance	Risk	Safety, Reserves & Operational Excellence
Independent Directors					
Farhad Ahrabi				√	√
David R. Collyer		Chair	√		√
John P. Dielwart				√	Chair
Harold N. Kvisle					
Michael G. McAllister				√	√
Kathleen M. O'Neill	Chair		√		
Herbert C. Pinder, Jr.		√	Chair		
William G. Sembo	√	√			
Nancy L. Smith	√			Chair	

All committees are comprised of independent Directors.

OFFICER BIOGRAPHIES

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

Terry M. Anderson, P. Eng.

Mr. Anderson is the President and Chief Executive Officer of ARC Resources and has overall management responsibility for the Corporation. Prior to February 2020, he was Senior Vice President and Chief Operating Officer of ARC Resources with responsibility for the execution of all aspects of ARC's operations and capital program. Prior to being appointed to Senior Vice President and Chief Operating Officer in December 2013, Mr. Anderson held the roles of Senior Vice President of Engineering and Land and Senior Vice President of Operations at ARC. He has over 25 years of operations and engineering experience. Prior to joining ARC in 2000, he worked at a major crude oil and natural gas company. Mr. Anderson holds a Bachelor of Science in Petroleum Engineering from the University of Wyoming. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and British Columbia (EGBC).

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

Mr. Bibby is the Senior Vice President and Chief Financial Officer of ARC Resources and oversees the finance, treasury, accounting, tax, risk management, capital markets, marketing, and information technology teams at ARC. Prior to being appointed to Senior Vice President and Chief Financial Officer in February 2020, Kris held the position of Vice President, Finance and Capital Markets. He has over 20 years of experience in finance and accounting roles within the crude oil and natural gas industry. Prior to joining ARC in 2014, Mr. Bibby held the position as Chief Financial Officer at a junior crude oil and natural gas company with international operations. He has a Bachelor of Commerce degree from the University of Saskatchewan, and is a member of the Chartered Professional Accountants of Alberta.

Christopher D. Baldwin, P. Geol.

Mr. Baldwin is the Vice President, Geosciences of ARC Resources and is responsible for the execution of ARC’s geophysical and geological activities. Mr. Baldwin joined ARC in 2009 and has over 20 years of experience in crude oil and natural gas exploration, development, geology, and geophysics. Prior to joining ARC, Mr. Baldwin held positions with large and intermediate crude oil and natural gas companies. Mr. Baldwin holds a Bachelor of Science in Geology from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Ryan V. Berrett, B. Mgmt, MBA

Mr. Berrett is the Vice President, Marketing of ARC Resources and coordinates all marketing activities to ensure market access for ARC’s production. He has over 15 years of accounting, finance, and marketing experience, having started his career at ARC in 2003. Mr. Berrett has led ARC’s marketing activities since 2010. Mr. Berrett holds a Bachelor of Management degree from the University of Lethbridge and an Executive Master in Business Administration in Global Energy from the University of Calgary’s Haskayne School of Business.

Sean R. A. Calder, P.L. Eng.

Mr. Calder is the Vice President, Production of ARC Resources, and manages all aspects of field production operations. He has over 20 years of broad 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. Prior to joining ARC, he worked at a major crude oil and natural gas company. Mr. Calder has a Bachelor of Applied Petroleum Engineering Technology degree from the Southern Alberta Institute of Technology (SAIT). He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA), as well as the Association of Science and Engineering Technology Professionals in Alberta (ASET).

Larissa M. Conrad, P. Eng.

Ms. Conrad is Vice President, Development and Planning of ARC Resources and is responsible for all development and reservoir engineering, strategic planning, business development, and mineral land activities. Ms. Conrad joined ARC in 2011 and has over 20 years of experience in reservoir, exploration, development and production engineering, as well as government and regulatory relations. Prior to joining ARC, she worked at a major Canadian crude oil and natural gas company. Ms. Conrad has a Bachelor of Science degree in Mechanical Engineering from the University of Waterloo and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Armin Jahangiri, P.Eng.

Mr. Jahangiri is the Vice President, Operations of ARC Resources and is responsible for overseeing the facilities, drilling and completions, health and safety, and the environment and regulatory teams. He has over 20 years of extensive industry experience in operations and major project development and execution both in North America and internationally. Mr. Jahangiri joined ARC in 2014, and since this time has taken on roles of increasing responsibility. Prior to joining ARC, he worked with a major Canadian crude oil and natural gas company and a global oilfield services company. Mr. Jahangiri holds a Bachelor of Science in Mechanical Engineering from the Sharif University of Technology, and a Master of Engineering in Reservoir Characterization from the University of Calgary. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and British Columbia (EGBC).

Lisa A. Olsen, B.A.

Ms. Olsen is the Vice President, Human Resources of ARC Resources, and is responsible for human resources, corporate governance, internal communications, office services, and records information management while ensuring ARC's unique and high-performance culture endures. Ms. Olsen joined ARC in 2008 and has over 20 years of experience as a human resources practitioner. Prior to joining ARC, Ms. Olsen spent over 10 years leading the human resources functions in both a Canadian crude oil and natural gas company as well as for a major international consumer brand. Ms. Olsen has a Bachelor of Communications from Simon Fraser University and a Human Resource Management Certificate from the BC Institute of Technology.

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

Mr. Zawalsky acts as Corporate Secretary for ARC Resources. He is a managing partner at the law firm of Burnet, Duckworth & Palmer LLP, and has over 30 years of experience in securities and corporate law including securities offerings, mergers and acquisitions, and corporate governance. Mr. Zawalsky is currently a Director for a number of public and private energy companies including NuVista Energy Ltd., PrairieSky Royalty Ltd., and Whitecap Resources Ltd.

AUDIT COMMITTEE DISCLOSURES

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

MEMBERS OF THE AUDIT COMMITTEE

As of March 1, 2021, the members of the Audit Committee are Kathleen O'Neill (Chair), William Sembo, and Nancy Smith; each is independent and financially literate within the meaning of NI 52-110. Additionally, Ms. Kathleen O'Neill and Ms. Nancy Smith 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 is a Corporate Director and has extensive experience in accounting and financial services. Previously, she was an Executive Vice-President of the Bank of Montreal (BMO) Financial Group with accountability for a number of major business units. Prior to joining BMO Financial Group in 1994, she was a partner with PricewaterhouseCoopers LLP. Ms. O'Neill is an FCPA, FCA (Fellow of Institute of Chartered Accountants) and has an ICD.D designation from the Institute of Corporate Directors. Ms. O'Neill was a member of the Steering Committee on Enhancing Audit Quality sponsored by the Chartered Professional Accountants of Canada and the Canadian Public Accountability Board. Ms. O'Neill is the past Chair of St. Joseph's Health Centre and St. Joseph's Health Center Foundation of Toronto. She is a current director of the Ontario Teachers' Pension Plan and chairs its Audit and Actuarial Committee. In 2014, 2015, and 2016, Ms. O'Neill was awarded Canada's Most Powerful Women: Top 100 Award by the Women's Executive Network and was inducted into the Hall of Fame in 2017.

William G. Sembo

Mr. Sembo has over 45 years of industry and financial services experience. He retired from his role as Vice Chairman at RBC Capital Markets LLC in 2013. Mr. Sembo has spent the majority of his career working in or supporting, as a financial advisor, the global energy industry and has expertise in investment banking, corporate credit, and mergers and acquisitions. Prior to joining RBC in 1986, Mr. Sembo held corporate finance and financial planning positions with Toronto Dominion Bank and Asamera Inc., respectively, and is currently an advisor with Lazard Canada Inc. Aside from his capital markets expertise, he brings a broad base of governance experience to ARC having or currently serving as a director or board chair for both private and public boards as well as numerous not-for-profit organizations. Mr. Sembo has a Bachelor of Arts (Economics) from the University of Calgary.

Nancy L. Smith

Ms. Smith is a Director and member of the Investment Committee of ARC Financial Corp., Canada's largest energy-focused private equity manager. Prior to joining ARC Financial in 1999, she held executive positions in finance and upstream marketing at a Canadian integrated energy company and spent the first five years of her career in corporate banking. Ms. Smith received a Masters in Business Administration and a Bachelor of Arts (Economics) from the University of Alberta, and has an ICD.D designation from the Institute of Corporate Directors.

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, 2020 and 2019. 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		2020		2019
Audit Fees	$	683,891	$	720,458
Audit Related Fees [1]	$	42,800	$	—
All Other Fees [2]	$	52,410	$	52,029

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, 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 business, 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 business 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 shall 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 elects to advance its counterclaim against ARC, ARC expects to apply to lift the stay to prosecute its claim against ACCEL. ACCEL has not, at present, indicated an intention to pursue the counterclaim. Management does not expect the outcome of the counterclaim to result in a material outflow of resources by ARC.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

DIVIDENDS

DIVIDEND POLICY

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

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

Notwithstanding the foregoing, the amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors of ARC Resources and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditures, debt service requirements, operating expense, royalty burdens, foreign exchange rates, and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. For information relating to risks associated with dividends, see the section entitled “*Risk Factors - Dividends*” contained within the MD&A, available on ARC’s website at www.arcresources.com and on SEDAR at www.sedar.com.

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	2020	2019	2018
January	$0.05	$0.05	$0.05
February	$0.05	$0.05	$0.05
March	$0.02	$0.05	$0.05
April	—	$0.05	$0.05
May	—	$0.05	$0.05
June	$0.06	$0.05	$0.05
July	—	$0.05	$0.05
August	—	$0.05	$0.05
September	$0.06	$0.05	$0.05
October	—	$0.05	$0.05
November	—	$0.05	$0.05
December	$0.06	$0.05	$0.05
Total	**$0.30**	**$0.60**	**$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 2020 of the common shares on the TSX for the periods indicated (as quoted by Bloomberg).

Toronto Stock Exchange	High ($)	Low ($)	Volume
January	8.26	7.02	46,014,658
February	7.30	5.80	56,340,690
March	6.06	2.71	99,665,557
April	5.87	4.12	57,196,879
May	5.92	5.10	34,034,375
June	6.05	4.43	45,943,146
July	5.69	4.60	27,440,007
August	6.82	6.09	25,889,245
September	6.62	5.78	32,561,933
October	7.12	5.82	24,615,219
November	6.94	5.99	33,722,217
December	6.28	5.79	41,319,996

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.

Since early 2020, worldwide oversupply of crude oil, a lack of available storage capacity, and decreased demand due to the novel coronavirus COVID-19 ("COVID-19") pandemic have had a significant impact on the price of crude oil. In an effort to stabilize global crude oil markets, the Organization of the Petroleum Exporting Countries and a number of other oil-producing countries announced an agreement to cut crude oil production by approximately 10 million barrels per day in April 2020. This agreement contributed to rebalancing global crude oil markets. However, economic recovery has slowed in some respects due to a resurgence of COVID-19 and newly emerging virus variants in major economies.

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.

As discussed in the section entitled *"Transportation Constraints and Market Access"* below, one major constraint to the export of crude oil, natural gas, and NGLs is the deficit of transportation capacity to transport production from western Canada to the United States and other international markets. Although certain pipeline and other transportation and export projects are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges, and economic and other socio-political factors. Due, in part, to growing production in western Canada and a lack of new and expanded pipeline and rail infrastructure capacity, producers in western Canada have experienced low commodity pricing relative to other markets over the last several years.

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. ("Enbridge") Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, previously expected to be in-service in late 2019, has faced significant delays due to permitting difficulties in the United States. However, Minnesota regulators approved the final required permit for the project in November 2020. Certain segments of the Line 3 Replacement in North Dakota and Wisconsin are currently in operation and the Canadian portion of the replaced pipeline began commercial operation in December 2019. Construction of the Line 3 Replacement in Minnesota began in early December 2020; Enbridge expects the line to be in service in the fourth quarter of 2021.

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.

On March 31, 2020, TC Energy Corporation ("TC Energy") announced it would proceed with the Keystone XL Pipeline. TC Energy also announced that the Government of Alberta had made a US $1.1 billion equity investment in the project and would guarantee a US $4.2 billion project level credit facility. While construction on the Keystone XL Pipeline started in April 2020, the project remains subject to legal and regulatory barriers in the United States, including the cancellation of a presidential permit on January 20, 2021, that permits the Keystone XL Pipeline to operate across the international border.

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, potentially forcing the lines comprising this segment of the pipeline system to be shut down by May 2021. Enbridge filed a federal complaint in late November 2020 in the Unites 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 U.S. federal safety standards.

Marine Tankers

The Canadian 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.

Crude Oil and Bitumen by Rail

Following two train derailments that led to fires and crude oil spills in Saskatchewan, the federal government announced in February 2020 that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits. The order was updated in April 2020 and replaced in November 2020. The speed limits and other requirements established in Order MO 20-10 will remain in place until permanent rule changes are approved.

Enbridge Open Season

In August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier crude oil pipeline system. A common carrier pipeline must accept all products offered to it for transportation. If there is insufficient capacity to transport the volumes offered, the available capacity is pro-rated to accommodate all shippers. The changes that Enbridge intends to implement include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein shippers will have to commit to reserved space in the pipeline for a fixed term, with only 10 per cent of available capacity reserved for nominations. If the service change is approved, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without first obtaining prior regulatory approval to implement a contract carriage model. Following an expedited hearing process, the CER decided to shut down the open season. On December 19, 2019, Enbridge applied to the CER for approval of the proposed service and tolling framework. The regulatory hearing process is currently underway and a final decision from the CER is not expected until mid-2021. If Enbridge receives CER approval, it intends to hold the open season by the end of 2021.

Natural Gas and Liquefied Natural Gas ("LNG")

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 additional markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in western Canada for their natural gas, which in the last several years has generally been depressed relative to other 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. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline system (the "NGTL System") to prioritize deliveries into storage (the "Temporary Service Protocol"). The change stabilized supply and pricing, particularly during periods of maintenance on the system, but, in February 2021, the CER refused a request to extend the Temporary Service Protocol. However, 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 late 2019, TC Energy announced that it would sell 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.

The transaction closed in May 2020. 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 currently proceeding.

In addition to LNG Canada and the CGL Pipeline projects, various other LNG Projects have been proposed in Canada:

- In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada) Limited. However, both partners are looking to sell a portion or all of their interest in the project.
- Woodfibre LNG Limited, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. has proposed to build the Woodfibre LNG Project, a small-scale LNG processing and export facility near Squamish, British Columbia. The BCOGC approved a project permit for the Woodfibre LNG Project in July 2019 and a formal approval of the project is expected in the third quarter of 2021, with construction beginning shortly thereafter.
- GNL Québec Inc., the proponent of the Énergie Saguenay Project, is currently undergoing a federal impact assessment process for the construction and operation of an LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River in Québec. The Énergie Saguenay Project is currently slated for completion in 2026.
- Pieridae Energy Ltd.'s ("Pieridae") proposed Goldboro LNG project, located in Nova Scotia, would see LNG exported from Canada to European markets. Pieridae has agreements with Royal Dutch Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, but Pieridae has delayed its final investment decision until mid-2021.
- Finally, Cedar LNG Export Development Ltd.'s Cedar LNG Project near Kitimat, British Columbia, is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office (the "BC EAO") conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("IA Agency").

CURTAILMENT

In December 2018, the Government of Alberta announced that it would mandate a short-term and temporary curtailment of provincial crude oil and bitumen production. Curtailment first took effect on January 1, 2019. As contemplated in the *Curtailment Rules*, the Government of Alberta, on a monthly basis, required crude oil and bitumen producers producing more than 20,000 barrels per day to limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators that are subject to curtailment orders.

As of December 2020, monthly crude oil production limits are no longer in effect. However, the *Curtailment Rules*, which were set to be repealed on December 31, 2020, have been extended such that the Government of Alberta retains the ability to impose future production limits if needed.

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 United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, the implementation of the USMCA could have an impact on 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 United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia, and Europe.

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.

In response to COVID-19, the governments of Alberta and British Columbia announced measures to extend Crown leases that may have otherwise expired in the months following the implementation of pandemic response measures.

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.

The federal government also creates incentives and other financial aid programs intended to assist businesses operating in the crude oil and natural gas industry. Recently, these programs, including, but not limited to, programs that provide direct financial support to companies operating in the crude oil and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, including those programs created in response to the COVID-19 pandemic such as the various short-term loan programs and the Canada Emergency Wage Subsidy, for example, have been administered through federal agencies such as the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, Innovation, Science and Economic Development Canada and, in some cases, the Canada Revenue Agency.

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.

Alberta Royalty Regimes Summary				
Royalty Regime	**Product**	**Incentive Period**	**Post Incentive or Mid-Life (MRF)**	**Mature Phase (MRF)**
ARF - Royalty formulas based on price and production	Crude Oil	5%	0% to 40%	
	Natural Gas		5% to 36%	
	Liquids - C3 & C4 / C5+		Flat 30% / Flat 40%	
MRF - Royalty formulas based on price with a reduction for lower production during the mature phase	Crude Oil / Condensate / C5+	Pre-payout 5%	10% to 40%	Minimum 5%
	Natural Gas		5% to 36%	
	C3 /C4		10% to 36%	

British Columbia

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	**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 British Columbia'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.

On August 28, 2019, the *Impact Assessment Act* (the "IAA") replaced the *Canadian Environmental Assessment Act*, 2012. The enactment of the CERA and the IAA introduced a number of important changes to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer manage strategic, administrative, and policy considerations while adjudicative functions fall to independent commissioners. 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 IA Agency or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the crude oil and natural gas industry include pipelines that require more than 75 kilometres of new right-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. There is significant uncertainty surrounding the impact of the CERA and the IAA on crude oil and natural gas projects and there is concern that the changes brought about by this new legislation will result in projects not being approved or experiencing increased delays in approvals.

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 Ac*t and a number of related statutes including the *Oil and Gas Conservation Ac*t (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 in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental, and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The Ministry of Indigenous Relations (the "MIR") 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 activities. 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, emphasizes 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 BC EAO 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 completion 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. However, 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. 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 RATING PROGRAMS

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 a Liability Management Rating Program (the "AB LMR Program"), which is currently undergoing changes, including a name change to the "Liability Management Framework" (the "AB LMF"); however, specific details concerning this new program remain forthcoming. The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities, and pipelines. It consists of three distinct programs: the Oilfield Waste Liability Program (the "AB OWL Program"), the Large Facility Liability Management Program (the "AB LFP"), and the Licensee Liability Rating Program (the "AB LLR Program"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the licensee, must reduce its liabilities or provide the AER with a security deposit. Failure to do so may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating.

Complementing 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 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 LFP. 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.

As a result of the Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as 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 will come into force on proclamation.

As mentioned above, the Government of Alberta announced in July 2020 that the AB LMF will replace the AB LMR Program and its constituent programs. Among other changes under the AB LMF, the AB LMR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health and will consider a wider variety of factors than those considered under the AB LMR Program and establish clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. Importantly, the AB LMF will also provide proactive support to distressed operators and will require mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets.

The Government of Alberta followed the announcement of the AB LMF with amendments to the *Oil and Gas Conservation Rules* and the *Pipeline Rule*s 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.

In response to the increase in orphaned crude oil and natural gas sites and the environmental risks associated therewith, the AER is amending its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("Directive 067"), which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information. All transfers of well, facility, and pipeline licences in the province are subject to AER approval. The AER has published a draft of an amended Directive 067 to implement some of these changes (the "Draft Directive"). The changes introduced by the Draft Directive include building on the AER's corporate and financial disclosure requirements for parties who wish to acquire, hold, or transfer licences in Alberta, and broadening the AER's discretion to withhold or revoke licensees' privileges if they are assessed as posing an "unreasonable risk". The feedback that the AER receives will be considered in the determination of the final revised Directive 067, and the rollout of the AB LMF may require changes to other Directives as well. As a result, ARC's ongoing and future transactions may be affected in this period of transition, resulting in processing delays for licence transfers and regulatory uncertainty as the criteria and requirements for licensees are subject to change.

To address abandonment and reclamation liabilities in Alberta, the AER implements, from time to time, programs intended to encourage the decommissioning, remediation, and reclamation of inactive or marginal crude oil and natural gas infrastructure. Beginning in 2015, for example, the AER oversaw the Inactive Well Compliance Program, a five-year program intended to address the growing inventory of inactive and noncompliant wells in Alberta. More recently, the AER announced a voluntary area-based closure ("ABC") program in 2018. 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.

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.

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, the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan, and British Columbia. However, these funds are being administered by regulatory authorities in each province. In Alberta, the Ministry of Energy is disbursing its $1 billion share of the federally provided funds through the Site Rehabilitation Program. In addition to the funds administered by the respective provincial governments, the federal government announced a $200 million loan to Alberta's Orphan Fund. The Government of British Columbia is disbursing its $120 million share of the federally provided funds through three programs: the Dormant Sites Reclamation Program, the Orphan Sites Supplemental Reclamation Program, and the Legacy Sites Reclamation Program.

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. Decisions about a prospective carbon market and emissions cuts have been delayed until the next climate conference, which is scheduled to take place in November 2021.

The Government of Canada has pledged to cut its emissions by 30 per cent from 2005 levels by 2030, but indicated in its recent Speech from the Throne that it may implement policy changes to exceed this target.

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. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50 per tonne of CO_2e in 2022. On December 11, 2020, however, 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, 2021, the minimum price permissible under the GGPPA is $40 per tonne of CO_2e.

Alberta, Saskatchewan, and Ontario have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In the Saskatchewan and Ontario references, the appellate Courts found the GGPPA to be constitutional; the Alberta Court of Appeal determined that the GGPPA is unconstitutional. All three judgments have been appealed to the Supreme Court of Canada. The hearing took place in September 2020, but the Court has not yet released its decision.

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 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 a $750 million Emissions Reduction Fund intended to support pollution reduction initiatives, including methane. Funds disbursed through this program will primarily take the form of repayable contributions to onshore and offshore crude oil and natural gas firms.

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.

On November 19, 2020, the federal government introduced the *Canadian Net-Zero Emissions Accountability Act* in Parliament. If passed, this Act will bind the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It will also establish rolling five-year emissions-reduction targets and require the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body and require 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.

Alberta

In June 2019, the federal fuel charge took effect in Alberta. In accordance with the GGPPA, the fuel charge payable in Alberta will increase from $30 per tonne to $40 per tonne on April 1, 2021. 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 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 and 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. ARC has voluntarily opted into the TIER program.

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. Together, these Directives will support Alberta in achieving its 2025 goal. 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 $40 per tonne of CO_2e. In response to the COVID-19 pandemic, the Government of British Columbia has delayed the scheduled increase to $45 per tonne of CO_2e until April 1, 2021.

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.

In January 2019, the BCOGC announced 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. These new rules came into effect on January 1, 2020. 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, 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 December 2020, the federal government introduced *Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act* ("Bill C-15"). Similar to British Columbia's DRIPA, the intention of Bill C-15, if passed, is to establish a process whereby the Government of Canada will 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 Bill C-15 may 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.

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 for the year ended December 31, 2020, 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

The following comprises particulars of every material contract of ARC that was entered into within the most recently completed financial year, or entered into before the most recently completed financial year which is still in effect, other than a contract entered into in the ordinary course of business:

1. Amended and Restated Credit Agreement dated as of November 6, 2014, as amended on November 23, 2016, November 1, 2017, October 31, 2018, and December 6, 2019; between ARC Resources and a syndicate of lenders, and an administrative agent, providing for an extendible revolving credit facility up to $950.0 million. The maturity date of the facility is December 15, 2023.

2. Uncommitted Master Shelf Agreement dated as of November 16, 2000 between ARC Resources and various purchasers, as amended and restated on December 15, 2005, and September 25, 2014, and as amended on September 27, 2019, and as amended on March 31, 2020, providing for the issuance and sale of up to an aggregate principal amount of US$350.0 million in notes of which US$150.0 million 3.72% Series E Notes due September 25, 2026, is currently outstanding. The Master Shelf Agreement expired on September 25, 2017.

3. Note Purchase Agreement dated as of April 14, 2009, between ARC Resources and various purchasers, as amended on January 1, 2011, as amended on September 27, 2019, and as amended on March 31, 2020, with respect to US$67.5 million 7.19% Series C Notes due April 14, 2016, US$35.0 million 8.21% Series D Notes due April 14, 2021, and $29.0 million 6.50% Series E Notes due April 14, 2016, of which US$nil, US$7.0 million and $nil million, respectively, are currently outstanding.

4. Note Purchase Agreement dated as of May 27, 2010, between ARC Resources and various purchasers, as amended on January 1, 2011, as amended on September 27, 2019, and as amended on March 31, 2020, with respect to US$150.0 million 5.36% Series F Notes due May 27, 2022, of which US$60.0 million is currently outstanding.

5. Note Purchase Agreement dated as of August 23, 2012, between ARC Resources and various purchasers as amended on September 27, 2019, and as amended on March 31, 2020, with respect to US$60.0 million 3.31% Series G Notes due August 23, 2021, US$300.0 million 3.81% Series H Notes due August 23, 2024, and $40.0 million 4.49% Series I Notes due August 23, 2024, of which US$12.0 million, US$240.0 million and $32.0 million, respectively, is currently outstanding.

6. Uncommitted Master Shelf Agreement dated as of March 13, 2019, between ARC Resources and various purchasers, providing for the issuance and sale of up to an aggregate principal amount of US$375.0 million in notes of which $nil is currently outstanding.

For more information in relation to these material contracts, see the section entitled "*Other Information Relating to Our Business - Borrowing*" contained within this Annual Information Form. Copies of each of these documents are available on SEDAR at www.sedar.com.

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 reserve evaluator, and PricewaterhouseCoopers LLP, our independent external auditor for the year ended December 31, 2020. 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, 2021, in respect of the Corporation's consolidated financial statements as at and for the year ended December 31, 2020. 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.

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 RESERVE 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, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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, 2020, 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 - M$)			
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, 2020	Canada	—	4,874,015	—	**4,874,015**

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 29, 2021.

/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 reserve evaluator has evaluated the Company's reserves data. The report of the independent qualified reserve 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 reserve evaluator;

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

c) reviewed the reserves data with management and the independent qualified reserve 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 reserve 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
Vice President, Development and Planning

/s/ John Dielwart
John Dielwart
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 1, 2021

APPENDIX C

MANDATE OF THE AUDIT COMMITTEE (February 25, 2021)

MANDATE OF THE AUDIT COMMITTEE

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

h. 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) 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 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.