UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 40-F

[Check one]

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**
OR

☑ **ANNUAL REPORT PURSUANT TO SECTION 13(a) or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: December 31, 2020 Commission File Number: 1-34513

CENOVUS ENERGY INC.

(Exact name of Registrant as specified in its charter)

Not applicable
(Translation of Registrant's name into English (if applicable))

Canada
(Province or other jurisdiction of incorporation or organization)

1311
(Primary Standard Industrial
Classification Code Number (if applicable))

Not applicable
(I.R.S. Employer
Identification Number (if applicable))

4100, 225 - 6 Avenue S.W.
Calgary, Alberta, Canada T2P 1N2
(403) 766-2000
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
28 Liberty Street
New York, New York 10005
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code)
of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common shares, no par value (together with associated common share purchase rights)	**CVE**	**New York Stock Exchange**
Warrants (each warrant entitles the holder to purchase one common share at an exercise price of C$6.54 per share)	**CVE WS**	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act.

None
(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None
(Title of Class)

For annual reports indicate by check mark the information filed with this Form:

☑ Annual information form ☑ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

1,228,869,903

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☑ No ☐

Indicate by check mark whether the Registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit such files).

Yes ☑ No ☐

Indicate by check mark whether the Registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the Registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange
Act. ☐

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report.

☑

The annual report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, each of the Registrant's Registration Statements under the Securities Act of 1933, as amended: Form F-10 (File No. 333-233702), Form S-8 (File Nos. 333-163397 and 333-251886), Form F-3D (File No. 333-202165).

Principal Documents

The following documents, filed as Exhibits 99.1, 99.2, 99.3 and 99.4 to this annual report on Form 40-F, are hereby incorporated by reference in this annual report on Form 40-F:

(a) Annual Information Form of Cenovus Energy Inc. for the fiscal year ended December 31, 2020.

(b) Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2020.

(c) Consolidated Financial Statements of Cenovus Energy Inc. for the fiscal year ended December 31, 2020.

(d) Supplementary Information – Oil and Gas Activities (unaudited) for the fiscal year ended December 31, 2020.

ADDITIONAL DISCLOSURE

Certifications and Disclosure Regarding Controls and Procedures.

(a) Certifications. See Exhibits 99.5 99.6, 99.7 and 99.8 to this annual report on Form 40-F.

(b) Disclosure Controls and Procedures. As of the end of the Registrant's fiscal year ended December 31, 2020, an evaluation of the effectiveness of the Registrant's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was carried out by the Registrant's management with the participation of the principal executive officer and principal financial officer. Based upon that evaluation, the Registrant's principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the Registrant's disclosure controls and procedures are effective to ensure that information required to be disclosed by the Registrant in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's (the "Commission") rules and forms and (ii) accumulated and communicated to the Registrant's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

It should be noted that while the Registrant's principal executive officer and principal financial officer believe that the Registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Registrant's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

(c) Management's Annual Report on Internal Control Over Financial Reporting. The required disclosure is included in the "Report of Management" that accompanies the Registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2020, filed as Exhibit 99.3 to this annual report on Form 40-F.

(d) Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the "Report of Independent Registered Public Accounting Firm" that accompanies the Registrant's Consolidated Financial Statements for the fiscal year ended December 31, 2020, filed as Exhibit 99.3 to this annual report on Form 40-F.

(e) Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2020, there was no change in the Registrant's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Registrant's internal control over financial reporting.

Notices Pursuant to Regulation BTR.

None.

Audit Committee Financial Expert.

The Registrant's board of directors has determined that Claude Mongeau and Jane E. Kinney, who are members of the Registrant's audit committee, each qualify as an "audit committee financial expert" (as such term is defined in paragraph (8) of General Instruction B to Form 40-F), and that each of the following members of the Registrant's audit committee is "independent" as that term is defined in the rules of the New York Stock Exchange: Claude Mongeau, Jane E. Kinney, Richard J. Marcogliese and Wayne E. Shaw.

Code of Ethics.

The Registrant has adopted a "code of ethics" (as that term is defined in paragraph (9) of General Instruction B to Form 40-F), entitled the "Code of Business Conduct & Ethics", that applies to all of its employees, including its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions.

The Code of Business Conduct & Ethics (the "Code") is available for viewing on the Registrant's website at www.cenovus.com and is available in print to any person without charge, upon request. Requests for copies of the Code should be made by contacting the Registrant's Corporate Secretarial Department, Cenovus Energy Inc., 225 - 6 Avenue S.W., P.O. Box 766, Calgary, Alberta, Canada T2P 0M2. Any amendments to the Code from time to time will be posted to the Registrant's website within five business days of the amendment and will remain available for a twelve-month period. Information on or connected to our website, even if referred to herein, does not constitute part of this annual report on Form 40-F.

Since the adoption of the Code, there have not been any waivers, including implicit waivers, granted from any provision of the Code.

Principal Accountant Fees and Services.

The required disclosure is included under the heading “Audit Committee - External Auditor Service Fees” in the Registrant’s Annual Information Form for the fiscal year ended December 31, 2020, filed as Exhibit 99.1 to this annual report on Form 40-F.

Pre-Approval Policies and Procedures and Percentage of Services Approved by Audit Committee.

The required disclosure is included under the heading “Audit Committee - Pre-Approval Policies and Procedures” and “Audit Committee – External Auditor Service Fees” in the Registrant’s Annual Information Form for the fiscal year ended December 31, 2020, filed as Exhibit 99.1 to this annual report on Form 40-F. All fees have been pre-approved by the Audit Committee and therefore none of the services therein were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

Off-Balance Sheet Arrangements.

The Registrant does not have any “off-balance sheet arrangements” (as that term is defined in paragraph (11) of General Instruction B to Form 40-F) that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

Tabular Disclosure of Contractual Obligations.

The required disclosure is included under the heading “Liquidity and Capital Resources - Contractual Obligations and Commitments” in the Registrant’s Management’s Discussion and Analysis for the fiscal year ended December 31, 2020, filed as Exhibit 99.2 to this annual report on Form 40-F.

Identification of the Audit Committee.

The Registrant has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Jane E. Kinney, Richard J. Marcogliese, Claude Mongeau (Chair) and Wayne E. Shaw.

Mine Safety Disclosure.

Not applicable.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

(1) The Registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

(2) Any change to the name or address of the agent for service of process of the Registrant shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the Registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

Date: February 9, 2021

CENOVUS ENERGY INC.

By: /s/ Jeffrey R. Hart
Name: Jeffrey R. Hart
Title: Executive Vice-President &
Chief Financial Officer

EXHIBIT INDEX

Exhibits	Documents
99.1	Annual Information Form of Cenovus Energy Inc. for the fiscal year ended December 31, 2020.
99.2	Management's Discussion and Analysis of Cenovus Energy Inc. for the fiscal year ended December 31, 2020.
99.3	Consolidated Annual Financial Statements of Cenovus Energy Inc. for the fiscal year ended December 31, 2020.
99.4	Supplementary Information – Oil and Gas Activities (unaudited) for the fiscal year ended December 31, 2020.
99.5	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
99.6	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
99.7	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
99.8	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350.
99.9	Consent of PricewaterhouseCoopers LLP.
99.10	Consent of McDaniel & Associates Consultants Ltd.
99.11	Consent of GLJ Ltd.
101	Interactive data file

Exhibit 99.1



Cenovus Energy Inc.

Annual Information Form

For the Year Ended December 31, 2020

February 8, 2021

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FORWARD-LOOKING INFORMATION

In this Annual Information Form ("AIF"), unless otherwise specified or the context otherwise requires, references to "the Corporation" or "Cenovus" mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries as at December 31, 2020 and, for greater certainty, unless otherwise specified or the context otherwise requires, excludes Husky Energy Inc. ("Husky") and the subsidiaries of, and partnership interests held by, Husky and its subsidiaries.

This AIF contains forward-looking statements and other information (collectively "forward-looking information") about Cenovus's current expectations, estimates and projections, made in light of the Corporation's experience and perception of historical trends. Although we believe that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. This forward-looking information is identified by words such as "anticipate", "believe", "capacity", "could", "estimate", "expect", "focus", "forecast", "future", "plan", "potential", "project", "target", "may", "schedule" or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: the impact of the Husky Arrangement (defined below) on certain reserves data and other oil and gas information, including any *pro forma* information relating to the Husky Arrangement; Cenovus's ability to fund future development costs; insurance proceeds; production from Cenovus's Conventional segment providing an economic hedge for the natural gas required as a fuel source at the Corporation's oil sands and refining operations; strategy and related milestones; schedules and plans; determination of the operating and reporting segments for the combined company; the Corporation's ability to realize the best margins and netbacks for Cenovus's products; expected timing for oil sands expansion phases and associated expected production capacities; projections for 2021 and future years and plans and strategies to realize such projections; the anticipated timelines of the development and completion of projects; the anticipated relaunching of suspended projects; the focus of future development and exploration activities; future opportunities for oil and gas development; forecast operating and financial results, including forecast sales prices, costs and cash flows; priorities for and approach to capital investment decisions or capital allocation; planned capital expenditures, including the amount, timing and financing thereof; the planned amalgamation of Cenovus and Husky; techniques expected to be used to recover reserves and forecasts of the timing thereof; future abandonment and reclamation costs and the timing of payments in relation thereto; expected payment of taxes, royalties and other payments; potential impacts of various identified risk factors, including those related to commodity prices and climate change; expected future production, including the timing, stability or growth thereof; expected reserves and related information, including reserves life index and any *pro forma* reserves information relating to the Husky Arrangement, future net revenue and future development costs; expected capacities, including for projects, processing, transportation and refining; improving cost structures, forecast cost savings and the sustainability thereof; anticipated timelines for future regulatory, partner or internal approvals; future impact of regulatory measures; forecast commodity prices and trends and expected impacts to Cenovus; potential impacts of various risks, including those related to commodity prices and climate change; and future use and development of technology, including expected effects on land footprint, steam to oil ratios and environmental performance and sustainability. Readers are cautioned not to place undue reliance on forward-looking information as the Corporation's actual results may differ materially from those expressed or implied.

Statements relating to "reserves" are deemed to be forward looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the term reserves life index may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not reflect the actual life of the reserves.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include, but are not limited to: Cenovus's ability to realize the anticipated benefits of the Husky Arrangement; Cenovus's ability to successfully integrate the business of Husky, including new business activities, assets, operating areas, regulatory jurisdictions, personnel and business partners for Cenovus; the accuracy of any assessments undertaken or information provided by Husky in connection with the Husky Arrangement and any resulting *pro forma* information, including related to reserves; forecast oil and natural gas, natural gas liquids ("NGLs"), condensate and refined products prices, and light-heavy crude oil price differentials; the absence of significant adverse changes to legislation and regulations, Indigenous relations, interest rates, foreign exchange rates, competitive conditions and the supply and demand for crude oil and natural gas, NGLs, condensate and refined products; the political, economic and social stability of jurisdictions in which Cenovus operates; the absence of significant disruption of operations, including as a result of harsh weather, natural disaster, accident, civil unrest or other similar events; the prevailing climatic conditions in Cenovus's operating locations; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further cost reductions and sustainability thereof; applicable

royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to the Corporation's share price and market capitalization over the long term; the sufficiency of existing cash balances, internally generated cash flows, existing credit facilities, management of the Corporation's asset portfolio and access to capital markets to fund future development costs and dividends, including any increase thereto; production from the Corporation's Conventional segment will provide an economic hedge for the natural gas required as a fuel source at both the Corporation's oil sands and refining operations; future narrowing of crude oil differentials; the ability of Cenovus's refining capacity, dynamic storage, existing pipeline commitments, financial hedge transactions and plans to ramp up crude-by-rail loading capacity to partially mitigate a portion of Cenovus's WCS crude oil volumes against wider differentials; the Corporation's ability to produce from oil sands facilities on an unconstrained basis; estimates of quantities of crude oil, bitumen, natural gas, NGLs and condensate from properties and other sources not currently classified as proved; the accuracy of accounting estimates and judgments; future use and development of technology and associated expected future results; the Corporation's ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects, development programs or stages thereof; the Corporation's ability to generate sufficient cash flow to meet current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; the Corporation's ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; Cenovus's ability to access sufficient capital and insurance coverage to pursue development plans; the stability of general domestic and global economic, market and business conditions; forecast inflation and other assumptions inherent in Cenovus's 2021 guidance available on cenovus.com and as set out below; Cenovus's ability to access and implement all technology and equipment necessary to achieve expected future results, and that such results are realized.

2021 guidance, as updated January 28, 2021, and available on cenovus.com, assumes: Brent prices of US$49.50/bbl, WTI prices of US$46.50/bbl; WCS of US$32.50/bbl; AECO natural gas prices of $2.50/Mcf; Chicago 3-2-1 crack spread of US$11.00/bbl; and an exchange rate of $0.78 US$/C$.

The risk factors and uncertainties that could cause actual results to differ materially from the forward-looking information, include, but are not limited to: the effect of the COVID-19 pandemic on the Corporation's business, including any related restrictions, containment, and treatment measures taken by varying levels of government in the jurisdictions in which we operate; the success of our new COVID-19 workplace policies and the return of our people to our workplaces; Cenovus's ability to realize the anticipated benefits of the Husky Arrangement in a timely manner or at all; the ability of Cenovus and Husky to amalgamate; Cenovus's ability to successfully integrate Husky's business with its own in a timely and cost effective manner or at all; the effects of entering new business activities; unforeseen or undisclosed liabilities associated with the Husky Arrangement; the inaccuracy of any assessments undertaken in connection with the Husky Arrangement and any resulting *pro forma* information; the inaccuracy of any historical or reserves information provided by Husky and of any resulting *pro forma* information; Cenovus's ability to access or implement some or all of the technology necessary to efficiently and effectively operate the Corporation's assets and achieve expected future results; the effect of the Husky Arrangement on relationships with customers, suppliers and other third parties; the effect of Cenovus's increased indebtedness; the effect of new significant shareholders; volatility of and other assumptions regarding commodity prices; the impact of production agreements among OPEC and non-OPEC members; foreign exchange risk, including related to agreements denominated in foreign currencies; the effectiveness of the Corporation's risk management program, including the impact of derivative financial instruments, the success of hedging strategies and the sufficiency of the Corporation's liquidity position; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; the accuracy of Cenovus's share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in Cenovus's marketing operations, including credit risks, exposure to counterparties and partners, including the ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of the Corporation's crude-by-rail terminal, including health, safety and environmental risks; Cenovus's ability to maintain desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; the Corporation's ability to access various sources of insurance coverage and debt and equity capital, generally, and on acceptable terms; Cenovus's ability to finance growth, capital expenditures and dividends, including any increases thereto; changes in credit ratings applicable to Cenovus or any of its securities; the accuracy of reserves estimates, future production and future net revenue estimates, including any *pro forma* information relating to the Husky Arrangement; the accuracy of accounting estimates and judgements; Cenovus's ability to replace and expand oil and gas reserves; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project development; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of the Corporation's assets or goodwill from time to time; Cenovus's ability to maintain relationships with its partners and to successfully manage and operate our integrated operations and businesses; reliability of Cenovus's assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and

manufacturing processes; ability to successfully complete development programs; the occurrence of unexpected events that result in operational interruptions, including blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, gaseous leaks, migration of harmful substances, loss of containment, releases or spills, including releases or spills from offshore facilities and shipping vessels at terminals or hubs and as a result of pipeline or other leaks; extreme weather events, natural disasters, iceberg incidents, acts of vandalism and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; the cost and availability of equipment necessary to Cenovus's operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and Cenovus's reputation, social license to operate and litigation related thereto; unexpected cost increases or technical difficulties in operating, constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and equipment and its application to our business, including potential cyberattacks; geo-political and other risks associated with our international operations; risks associated with climate change and Cenovus's assumptions relating thereto; the timing and the costs of well and pipeline construction; the Corporation's ability to access markets and secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and Cenovus's ability to attract and retain, critical talent; possible failure to obtain and retain qualified leadership and personnel, and equipment in a timely and cost efficient manner; changes in labour demographics and relationships, including with any unionized workforces; unexpected abandonment and reclamation costs; changes in the regulatory framework, permits, or approvals in any of the locations in which Cenovus operates or to any of the infrastructure upon which Cenovus relies; government actions or regulatory initiatives to curtail energy operations or pursue broader climate change agendas; changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on Cenovus's business, financial results and Consolidated Financial Statements; changes in general economic, market and business conditions; the political, social and economic conditions in the jurisdictions in which Cenovus operates or supplies; the status of our relationships with the communities in which we operate, including with Indigenous communities; the occurrence of unexpected events such as protests, epidemics, pandemics, war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of Cenovus's material risk factors, refer to "Risk Management and Risk Factors" in the Corporation's annual 2020 Management's Discussion and Analysis ("MD&A"), which section of the MD&A is incorporated by reference into this AIF, and to the risk factors described in other documents Cenovus files from time to time with securities regulatory authorities in Canada, available on SEDAR at sedar.com, and with the U.S. Securities and Exchange Commission on EDGAR at sec.gov, and on the Corporation's website at cenovus.com. Additional information concerning Husky's business and assets as of December 31, 2020 may be found in the annual information form of Husky dated February 8, 2021 for the year ended December 31, 2020 (the "Husky AIF") and Husky's management's discussion and analysis of the financial and operating results for the year ended December 31, 2020 (the "Husky MD&A"), each of which is filed and available on SEDAR under Husky's profile at sedar.com and on EDGAR at sec.gov.

Information on or connected to Cenovus's website cenovus.com or Husky's website at huskyenergy.com does not form part of this AIF unless expressly incorporated by reference herein.

CORPORATE STRUCTURE

Cenovus Energy Inc. was formed under the *Canada Business Corporations Act* ("CBCA") by amalgamation of 7050372 Canada Inc. ("7050372") and Cenovus Energy Inc. (formerly Encana Finance Ltd. and referred to as "Subco") on November 30, 2009 pursuant to an arrangement under the CBCA involving, among others, 7050372, Subco and Encana Corporation (now Ovintiv Inc.). On January 1, 2011, Cenovus Energy Inc. amalgamated with its wholly-owned subsidiary, Cenovus Marketing Holdings Ltd., through a plan of arrangement approved by the Court of Queen's Bench of Alberta. On July 31, 2015, Cenovus Energy Inc. amalgamated with its wholly-owned subsidiary, 9281584 Canada Limited (formerly 1528419 Alberta Ltd.), by way of a vertical short-form amalgamation. On August 1, 2018, Cenovus Energy Inc. amalgamated with its wholly-owned subsidiary, 10904635 Canada Limited (formerly Cenovus FCCL Ltd.), by way of a vertical short-form amalgamation.

In connection with the Husky Arrangement (defined below), Cenovus's articles were amended effective December 30, 2020 to create:

- Cumulative Redeemable First Preferred Shares, Series 1 (the "Series 1 First Preferred Shares"),
- Cumulative Redeemable First Preferred Shares, Series 2 (the "Series 2 First Preferred Shares");
- Cumulative Redeemable First Preferred Shares, Series 3 (the "Series 3 First Preferred Shares");
- Cumulative Redeemable First Preferred Shares, Series 4 (the "Series 4 First Preferred Shares");
- Cumulative Redeemable First Preferred Shares, Series 5 (the "Series 5 First Preferred Shares");
- Cumulative Redeemable First Preferred Shares, Series 6 (the "Series 6 First Preferred Shares");
- Cumulative Redeemable First Preferred Shares, Series 7 (the "Series 7 First Preferred Shares"); and
- Cumulative Redeemable First Preferred Shares, Series 8 (the "Series 8 First Preferred Shares") (collectively, the "First Preferred Shares").

The Corporation's head and registered office is located at 4100, 225 – 6 Avenue S.W., Calgary, Alberta, Canada T2P 1N2.

INTERCORPORATE RELATIONSHIPS

Cenovus's material subsidiaries and partnerships as at December 31, 2020 are as follows:

Subsidiaries & Partnerships	Percentage Owned(1)	Jurisdiction of Incorporation, Continuance, Formation or Organization
Cenovus Energy Marketing Services Ltd.	100	Alberta
FCCL Partnership ("FCCL")	100	Alberta
WRB Refining LP ("WRB")(2)	50	Delaware

(1) Reflects all voting securities of all subsidiaries and partnerships beneficially owned, or controlled or directed, directly or indirectly, by Cenovus.
(2) Cenovus non-operating interest held through Cenovus Overseas Finance ULC and Cenovus US Holdings Inc.

As of December 31, 2020, the Corporation's remaining subsidiaries and partnerships each account for (i) less than 10 percent of the Corporation's consolidated assets as at December 31, 2020 and (ii) less than 10 percent of the Corporation's consolidated revenues for the year ended December 31, 2020. In aggregate, Cenovus's subsidiaries and partnerships not listed above did not exceed 20 percent of the Corporation's total consolidated assets or total consolidated revenues as at and for the year ended December 31, 2020.

On January 1, 2021, pursuant to a plan of arrangement under the *Business Corporations Act* (Alberta), Husky became a wholly-owned subsidiary of Cenovus (the "Husky Arrangement") and will remain as such until completion of a planned amalgamation among the two entities. See "The Husky Arrangement" and "Description of the Business Following the Husky Arrangement" for further information.

A description of Husky's significant subsidiaries and jointly-controlled entities is included in the Husky AIF, which is filed and available on SEDAR under Husky's profile at sedar.com and on EDGAR at sec.gov.

GENERAL DEVELOPMENT OF THE BUSINESS

OVERVIEW

As at December 31, 2020, Cenovus was an integrated energy company headquartered in Calgary, Alberta. Cenovus is in the business of developing, producing and marketing crude oil, natural gas and NGLs in Canada, and also conducts marketing activities and owns refining interests in the United States ("U.S.").

As at December 31, 2020, all of Cenovus's oil and natural gas reserves and production were located in Canada, within the provinces of Alberta and British Columbia. As at December 31, 2020, Cenovus had a land base of approximately 5.2 million net acres. The estimated proved plus probable reserves life index at December 31, 2020 was approximately 39 years.

BUSINESS SEGMENTS

As at December 31, 2020, the Corporation's reportable segments were as follows:

Oil Sands

Cenovus's Oil Sands segment includes the development and production of bitumen in northeast Alberta. Cenovus's bitumen assets include Foster Creek and Christina Lake as well as Narrows Lake and other projects in the early stages of development.

Conventional

The Conventional segment includes approximately 3.6 million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and NGLs. The assets are located in Alberta and British Columbia and include interests in numerous natural gas processing facilities (collectively, the "Conventional Assets").

Refining and Marketing

Cenovus's Refining and Marketing segment includes transporting and selling crude oil, natural gas and NGLs and joint ownership of two refineries in the U.S. with the operator, Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.

Corporate and Eliminations

This segment primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative ("G&A"), financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Corporation's rail terminal, crude oil production used as a feedstock by the Refining and Marketing segment and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices.

THREE YEAR HISTORY

The following describes significant events and conditions that have influenced the development of Cenovus's business during the last three financial years:

2018

- **Sale of Suffield assets.** In the first quarter, Cenovus completed the sale of its Suffield crude oil and natural gas operations for cash proceeds of $512 million, before closing adjustments.
- **New Chief Financial Officer.** In the second quarter, Jon McKenzie was appointed Cenovus's Executive Vice-President & Chief Financial Officer.
- **Sale of Cenovus Pipestone Partnership.** In the third quarter, Cenovus completed the sale of its general partnership that held the natural gas and liquids business in northwestern Alberta for cash proceeds of $625 million, before closing adjustments.
- **Debt reduction.** In October, Cenovus redeemed US$800 million of its US$1.3 billion unsecured notes due October 2019. In December, Cenovus repurchased a principal amount of US$76 million of unsecured notes for US$69 million.
- **Sublease of excess office space.** In the third quarter, Cenovus subleased an additional eight floors of The Bow tower in Calgary, Alberta, further reducing Cenovus's long-term fixed real estate costs.
- **Continued wide differentials.** The differentials between West Texas Intermediate ("WTI") and Western Canadian Select ("WCS") averaged US$26.31 per barrel, a 120 percent increase compared with 2017, reaching a record of US$52.00 per barrel in the fourth quarter. Average WCS prices remained flat in 2018 in relation to 2017.
- **Government production curtailment.** On December 2, 2018, the Government of Alberta announced a temporary mandatory oil production curtailment for Alberta producers, starting in January 2019, to, among other things, address the record-high differentials between WTI and WCS at Hardisty.
- **Re-rated refinery processing capacity.** As a result of consistently strong operating performance, higher utilization rates and optimizations executed in 2018, both U.S. refineries were re-rated to reflect higher processing capacity effective January 1, 2019. Crude capacity at the Wood River Refinery was re-rated to 333,000 barrels per day from 314,000 barrels per day, while capacity at the Borger Refinery was re-rated to 149,000 barrels per day from 146,000 barrels per day.

2019

- **Debt reduction.** In 2019, Cenovus repurchased a principal amount of US$1,276 million of unsecured notes for US$1,214 million. In October, Cenovus also repaid US$500 million in unsecured notes upon maturity.
- **Achieved first steam from Christina Lake phase G.** In 2019, Cenovus began using steam from Christina Lake phase G to produce oil from other phases.
- **Ramped up crude-by-rail shipments.** Using its fleet of railcars, Cenovus ramped up shipments of crude-by-rail over the course of 2019 to exit the year with December loaded volumes averaging 105,985 barrels per day and rail sales of 91,059 barrels per day.
- **Alberta government extended curtailment.** In August, the Alberta government announced an extension of its mandatory oil production curtailment program to December 31, 2020.
- **Increased dividend by 25 percent.** In October, Cenovus announced a 25 percent increase to its dividend for the fourth quarter of 2019.
- **Moved headquarters.** In October, Cenovus completed the move of its headquarters in downtown Calgary, from The Bow tower to Brookfield Place.
- **Alberta government implemented Special Production Allowance program.** Cenovus qualified for a Special Production Allowance to produce crude oil above curtailment for incremental increases in rail shipments.
- **Re-rated Wood River Refinery processing capacity.** As a result of consistently strong operating performance, higher utilization rates and optimization executed in 2019, the Wood River Refinery crude capacity was re-rated to 346,000 barrels per day from 333,000 barrels per day, to reflect higher processing capacity, effective January 1, 2020.

2020

- **Environmental, social and governance (ESG) targets.** In the first quarter, Cenovus announced ESG targets in four key ESG focus areas: climate & greenhouse gas emissions, Indigenous engagement, land and wildlife and water stewardship.
- **Response to the COVID-19 pandemic.** In the first quarter, Cenovus took action to protect the health and safety of its staff and ensure the continuity of its business. Following the guidance of public health officials, the Corporation directed all staff who were able to do so to work from home, established mandatory self-isolation protocols and restricted travel policies as well as implemented active health screening, physical distancing and advanced cleaning and sanitation measures at its field operations.
- **Reduction of capital spending and suspension of crude-by-rail program.** On March 9, 2020, Cenovus announced a reduction to its 2020 capital program of approximately 32 percent in response to the significant decline in world benchmark crude oil prices. Cenovus also announced the temporary suspension of the crude-by-rail program and the deferral of final investment decisions on major growth projects.
- **Further reduction of capital spending and suspension of the dividend.** On April 2, 2020, Cenovus announced a further reduction to its 2020 capital program of $150 million, for a total year to date reduction in the 2020 capital program of 43 percent, along with additional cost-saving measures including the temporary suspension of its dividend.
- **Temporary additional credit facility liquidity.** In April, to further enhance its liquidity, the Corporation obtained commitments from several of its existing lenders for an additional $1.1 billion committed credit facility. On December 31, 2020, Cenovus cancelled the $1.1 billion committed credit facility prior to the closing of the Husky Arrangement.
- **Used dynamic storage to shift production into stronger price environment.** In the second quarter of 2020, Cenovus curtailed its oil sands production, storing mobilized oil in its reservoirs in response to the significant decline in crude oil prices. Production was ramped up by approximately 60,000 barrels per day in June and subsequent months in an improved price environment.
- **Senior note offering.** On July 30, 2020, Cenovus completed a public offering in the U.S. of US$1,000,000,000 in 5.375% senior unsecured notes due 2025.
- **Agreement with Husky.** On October 25, 2020 Cenovus and Husky announced the Husky Arrangement, an all-stock transaction valued at $23.6 billion, inclusive of debt, which would combine the two companies.
- **New leadership team.** In the fourth quarter, Cenovus announced the new executive leadership team of the combined company. The new leadership team was appointed on January 1, 2021 following the closing of the Husky Arrangement.
- **Alberta government curtailment program put on hold.** While the government's regulatory authority to curtail oil production extends through 2021, starting in December 2020, Alberta's government lifted monthly oil curtailment.
- **Marten Hills asset sale.** On November 9, 2020, Cenovus announced the sale of its Marten Hills heavy oil assets to Headwater Exploration Inc. ("Headwater") for a combination of cash, common share equity consideration and purchase warrants, while retaining a gross

overriding royalty interest in the property. The sale closed December 2, 2020.

- **Cenovus amends articles to create series of First Preferred Shares.** In connection with the Husky Arrangement, Cenovus's articles were amended effective December 30, 2020, to create a series First Preferred Shares.

2021

- **Cenovus acquires Husky.** Effective January 1, 2021, Cenovus completed the Husky Arrangement and acquired all of the issued and outstanding Husky common shares and Husky preferred shares. As a result of completing the Husky Arrangement, Husky became a wholly-owned subsidiary of Cenovus. Pursuant to the Husky Arrangement, holders of Husky common shares received 0.7845 of a Cenovus common share ("Common Share") and 0.0651 of a Cenovus warrant ("Cenovus Warrant"), in respect of each Husky common share held, resulting in the issuance of 788,517,905 Common Shares and 65,433,323 Cenovus Warrants, and holders of Husky preferred shares exchanged each Husky preferred share for one First Preferred Share with substantially identical terms. Each whole Cenovus Warrant entitles the holder to acquire one Common Share at an exercise price of $6.54 at any time up to January 1, 2026. In connection with the Husky Arrangement and pursuant to applicable securities laws, Cenovus will be filing a business acquisition report containing *pro forma* financial statements of the combined company as of December 31, 2020.
- **Reconstitution of the Board.** Concurrently with the completion of the Husky Arrangement, Cenovus's board of directors (the "Board"), and each committee of the Board, were reconstituted, with each of Canning K. N. Fok, Eva L. Kwok, Wayne E. Shaw and Frank J. Sixt being appointed to the Board.

PRIOR TO THE HUSKY ARRANGEMENT

OIL SANDS

Cenovus's Oil Sands segment includes 100 percent ownership of the Foster Creek and Christina Lake assets, both of which are producing. In addition, the Corporation has several emerging projects in the early stages of development, including 100 percent owned projects at Narrows Lake and Telephone Lake. The Oil Sands segment also includes Cenovus's Athabasca natural gas property. All of the gas produced from the Athabasca natural gas property since April 2018 is used as fuel at the adjacent Foster Creek operation.

As at December 31, 2020, Cenovus held bitumen rights of approximately 1.6 million gross acres (1.6 million net acres) within the Athabasca and Cold Lake areas, as well as the exclusive rights to lease an additional 536,000 gross acres on the Cold Lake Air Weapons Range, an active military base.

Development Approach

Cenovus uses steam-assisted gravity drainage ("SAGD") technology to recover bitumen. The Corporation does not employ mining techniques for extraction and none of its reserves are suitable for extraction using mining techniques. SAGD involves injecting steam into the reservoir to enable bitumen to be pumped to the surface. Cenovus applies a manufacturing-like, phased approach to developing its oil sands assets. This approach incorporates learnings from previous phases into future growth plans, helping the Corporation to minimize costs.

Technology

Cenovus continues to focus on technologies which are targeted to lower its cost structure, improve margins, and reduce greenhouse gas emissions amid continuing price uncertainty, a lower carbon future, increased interest in corporate sustainability efforts and regulatory changes.

Foster Creek

Cenovus has a 100 percent working interest in Foster Creek. It is located on the Cold Lake Air Weapons Range and has a reservoir depth up to 500 meters below the surface. Foster Creek produces from the McMurray formation using SAGD technology.

The Corporation holds surface access rights from the governments of Canada and Alberta and bitumen rights from the Government of Alberta for exploration, development and transportation from areas within the Cold Lake Air Weapons Range. In addition, Cenovus holds exclusive rights to lease several hundred thousand acres of bitumen rights in other areas on the Cold Lake Air Weapons Range on the Corporation's and/or its assignee's behalf.

Production from phases A through G at Foster Creek averaged 163,210 barrels per day in 2020 (159,598 barrels per day in 2019).

Cenovus operates a 98-megawatt natural gas-fired cogeneration facility in conjunction with Foster Creek. The steam and power generated by the facility is presently being used within the SAGD operation and any excess power generated is being sold into the Alberta power pool.

Christina Lake

Cenovus has a 100 percent working interest in Christina Lake. It is located approximately 120 kilometers south of Fort McMurray, Alberta and has a reservoir depth up to 375 meters below the surface. Christina Lake produces from the McMurray formation using SAGD technology.

Production from phases A through G at Christina Lake averaged 218,513 barrels per day in 2020 (194,659 barrels per day in 2019). Cenovus operates a 100-megawatt natural gas-fired cogeneration facility in conjunction with Christina Lake. The steam and power generated by the facility is presently being used within the SAGD operation and any excess power generated is being sold into the Alberta power pool. Phase G has an approved design capacity of 50,000 gross barrels per day. Cenovus began producing steam from phase G in 2019 and utilized the full facility in 2020.

Narrows Lake

Cenovus has a 100 percent working interest in Narrows Lake. Narrows Lake is located adjacent to Christina Lake and has a reservoir depth up to 375 meters below the surface.

In 2012, Cenovus received regulatory approval for 130,000 gross barrels per day of production capacity. Due to the low commodity price environment, and historically high price differentials, Cenovus had deferred new construction spending on phase A. Cenovus is now progressing development of the Narrows Lake resource by using existing infrastructure at Christina Lake.

Telephone Lake

Cenovus's 100 percent owned Telephone Lake property is located in the Borealis Region in northeastern Alberta, approximately 90 kilometers northeast of Fort McMurray, Alberta.

Cenovus received approval from the Alberta Energy Regulator in late 2014 for a SAGD project with initial production capacity of 90,000 gross barrels per day. The Corporation continues to assess what may be the optimal development plan for the Telephone Lake asset.

Capital Investment

In 2020, capital investment in the Oil Sands segment was $427 million, focused on sustaining programs related to existing production at Foster Creek and Christina Lake as well as the stratigraphic test well program to determine pad placement for sustaining well pads and expansions. Other capital investment related to advancing key initiatives and technology development costs.

CONVENTIONAL

Cenovus has western Canadian conventional crude oil and natural gas assets including undeveloped land, exploration and producing assets, and related infrastructure in Alberta and British Columbia. Cenovus's Conventional Assets include approximately 3.6 million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, with an average 75 percent working interest. In addition, the Conventional Assets include interests in numerous natural gas processing plants with an estimated net processing capacity of 1.2 billion cubic feet per day. The Conventional Assets are expected to provide short-cycle development opportunities with high return potential that complement Cenovus's long-term oil sands development. Conventional production is expected to provide an economic hedge for the natural gas required as a fuel source at both the Corporation's oil sands and refining operations.

On January 1, 2020 the Marten Hills heavy oil assets were moved into the Conventional segment from the Oil Sands segment. In the fourth quarter of 2020, Cenovus completed the sale of its Marten Hills heavy oil assets to Headwater for a combination of cash, common share equity consideration and purchase warrants, while retaining a gross overriding royalty interest in the property.

Elmworth-Wapiti

Cenovus is one of the largest operators and producers in the Elmworth-Wapiti area, located in northwest Alberta and northeast British Columbia. As of December 31, 2020, Cenovus held leasehold rights of 1.16 million net acres in this area.

The Elmworth-Wapiti area provides production potential from more than 10 formations, with the most prospective being the Falher and Dunvegan. It is a mature area that was historically developed with conventional vertical well technology. Cenovus has shifted to horizontal drilling in its development programs with a view to unlock the vast resource potential in the tight sand plays.

The primary processing facility in the area is the Cenovus-operated Elmworth plant. The Corporation holds significant working interests in four other major natural gas processing facilities in the region. Net production in Elmworth-Wapiti averaged 30,898 barrels of oil equivalent per day in 2020 (31,992 barrels of oil equivalent per day in 2019).

Kaybob-Edson

As of December 31, 2020, Cenovus held leasehold rights of approximately 733,602 net acres in the Kaybob-Edson area, which is situated in west-central Alberta. Target development is in the Montney and Lower Cretaceous formations where successful industry drilling has proven the resource potential of those formations in lands offsetting Cenovus acreage. In the Kaybob-Edson area, natural gas processing is primarily controlled by midstream operators and other oil and gas companies.

Cenovus has secured longer term contracts to manage both existing base and new-development volumes. Additionally, Cenovus operates natural gas processing facilities in the area, including the Peco and Wolf plants. Net production in Kaybob-Edson averaged 29,085 barrels of oil equivalent per day in 2020 (34,751 barrels of oil equivalent per day in 2019).

Clearwater

The Clearwater area is situated in west-central Alberta, south of Kaybob-Edson. As of December 31, 2020, Cenovus held leasehold rights of approximately 765,136 net acres. Cenovus's assets in the Clearwater area are characterized by multi-horizon, Cretaceous and Jurassic reservoirs at depths ranging from 1,900 meters to 3,000 meters, all with high NGL content in a predominantly gas prone area. This is a mature area historically developed with conventional vertical well technology, providing Cenovus with a series of lower risk horizontal drilling development programs. Cenovus operates natural gas processing facilities in the area, including the Sand Creek and Alder plants. Net production in Clearwater averaged 27,197 barrels of oil equivalent per day in 2020 (30,680 barrels of oil equivalent per day in 2019).

Capital Investment

In 2020, capital investment of $78 million in the Conventional segment focused on disciplined development, which encompassed maintaining safe and reliable operations, acquiring seismic data, start-up of a recompletion program to optimize existing production and commencement of a drilling program focusing on the Clearwater and Kaybob-Edson areas. The Kaybob-Edson area included the drilling of three net wells, completion of one net well, tie-in of one net well and other activities to maintain existing production and infrastructure. The Clearwater area focused on the drilling of three net wells and other activities to sustain existing production and infrastructure. The Elmworth-Wapiti area focused on activities to maintain existing production and infrastructure. Capital investment included expenditures on the Marten Hills heavy oil assets which were subsequently sold in the fourth quarter of 2020.

REFINING AND MARKETING

Cenovus's Refining and Marketing segment includes its U.S. refining non-operator ownership interests and operations involved in the coordination of Cenovus's marketing and transportation initiatives to optimize the value received for its products.

Refining

The refining interests allow Cenovus to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American light/heavy crude oil price differential fluctuations.

Through WRB, Cenovus has a 50 percent ownership interest in both the Wood River refinery located in Roxana, Illinois (the "Wood River Refinery") and the Borger refinery located in Borger, Texas (the "Borger Refinery"). Phillips 66, an unrelated U.S. public company, is the operator and managing partner of WRB. WRB has a management committee, which is composed of three Cenovus representatives and three Phillips 66 representatives, with each company holding equal voting rights. The refineries have a combined stated processing capacity of approximately 495,000 gross barrels per day of crude oil in 2020.

The following table summarizes the key operational results for the refineries in the periods indicated:

Refinery Operations(1)	2020	2019
Crude Oil Capacity (Mbbls/d)	495	482
Crude Oil Runs (Mbbls/d)	372	443
Heavy Oil	149	177
Light and Medium Oil	223	266
Crude Utilization (%)	75	92
Refined Products (Mbbls/d)		
Gasoline	195	223
Distillates	127	167
Other	63	76
Total	385	466

(1) Represents 100 percent of Wood River and Borger Refinery operations.

Wood River Refinery

Wood River Refinery ranks in the top 10 percent of approximately 130 refineries in the U.S., based on total crude oil capacity. It is located in Roxana, Illinois, approximately 25 kilometers northeast of St. Louis, Missouri. The Wood River Refinery processes light low-sulphur and heavy high-sulphur crude oil that it receives from North American crude oil pipelines to produce gasoline, diesel and jet fuel, petrochemical feedstock as well as petroleum coke and asphalt. The gasoline and diesel are transported via pipelines to markets in the upper U.S. Midwest. Other products are transported via pipeline, truck, barge and railcar to various markets.

Wood River Refinery's stated crude oil processing capacity for 2020 was 346,000 gross barrels per day. In 2020, approximately 57 percent of the crude oil processed at the Wood River Refinery consisted of Canadian heavy crude oil.

Borger Refinery

Borger Refinery is located in Borger, Texas, approximately 80 kilometers north of Amarillo, Texas. Borger Refinery processes mainly medium and heavy high-sulphur crude oil that it receives from North American pipeline systems to produce gasoline, diesel and jet fuel, along with NGLs and solvents. The refined products are transported via pipelines to markets in Texas, New Mexico, Colorado and the U.S. Mid-Continent.

Borger Refinery's stated crude oil processing capacity for 2020 was 149,000 gross barrels per day.

Capital Investment – Refining

In 2020, combined capital investment at both Wood River Refinery and Borger Refinery was $243 million net, focused on yield enhancement and reliability and maintenance projects.

Marketing

Cenovus's marketing activities are focused on optimizing netbacks of its production and asset base across crude oil, condensate, natural gas, and NGLs.

As part of managing market risk arising from optimization activities, Cenovus may enter into financial transactions from time to time. Details of these transactions in 2020 are provided in the notes to the Corporation's annual audited Consolidated Financial Statements for the year ended December 31, 2020.

Transportation

Cenovus continues to focus on near, mid, and long-term strategies to optimize netbacks for its production. As at December 31, 2020, Cenovus had entered into various transportation and storage commitments totaling $21 billion, $14 billion of which relates to pipelines that are in approval or construction phases but are not yet in service. With its committed capacity on pipeline projects, Cenovus has substantial potential future pipeline capacity to the Canadian West Coast and U.S. Gulf Coast.

The Corporation's portfolio of transportation commitments includes feeder pipelines from its production areas to the major Alberta trade centres, major pipelines to markets downstream of these centres and rail transportation agreements, including contracts with rail companies to transport heavy

crude oil from Alberta to various destinations on the U.S. Gulf Coast. Other transportation commitments are primarily related to diluent supply, railcar transportation as well as tankage and terminalling of both crude oil blend and condensate volumes.

Cenovus's transportation portfolio also includes a crude-by-rail terminal located at Bruderheim, Alberta that is connected to the rail lines of Canadian National Railway and Canadian Pacific Railway, and allows crude oil to be delivered to major demand centres across Canada and the U.S. The Corporation has lifted the suspension of its crude-by-rail program after temporarily suspending the program during the second quarter of 2020 in response to improving market conditions. Volumes loaded at the Bruderheim terminal averaged 32,213 barrels per day (65,293 barrels per day in 2019).

Capital Investment - Marketing

In 2020, Marketing capital investment was $33 million, focused on storage infrastructure projects.

THE HUSKY ARRANGEMENT

Pursuant to the Husky Arrangement, Husky became a wholly-owned subsidiary of Cenovus effective January 1, 2021 and will remain as such until completion of a planned amalgamation among the two entities. The combined company continues to operate as Cenovus, and remains headquartered in Calgary, Alberta.

For information regarding how the combined company's business has been reorganized and segmented as of January 1, 2021, see "Description of the Business Following the Husky Arrangement".

The following information describes the organization and segmentation of Husky's business as at December 31, 2020. Husky's business was organized under two business segments: (i) an integrated Canada-U.S. upstream and downstream corridor (the "Integrated Corridor"); and (ii) production located offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("Asia Pacific" and, collectively with Atlantic, "Offshore").

Integrated Corridor

Husky's business in the Integrated Corridor included (i) the Lloydminster Heavy Oil Value Chain; (ii) Oil Sands; (iii) Western Canada Production; (iv) U.S. Refining; and (v) Canadian Refined Products.

- The Lloydminster Heavy Oil Value Chain includes the exploration for, and development and production of, heavy crude oil and bitumen, and the production of ethanol. Blended heavy crude oil and bitumen are either sold directly to the Canadian market or transported utilizing the Husky Midstream Limited Partnership ("HMLP") pipeline systems to the existing Keystone pipeline and other pipelines to be sold in the U.S. downstream market. Heavy crude oil can be upgraded at Husky's upgrading facility located in Lloydminster, Saskatchewan (the "Lloydminster Upgrader") and at Husky's asphalt refinery in Lloydminster, Alberta (the "Lloydminster Asphalt Refinery") into synthetic crude oil, diesel fuel and asphalt. This business also includes the marketing and transportation of both Husky's own production and third-party commodity trading volumes of heavy crude oil, synthetic crude oil, asphalt and ancillary products. The sale and transportation of Husky's production and third-party commodity trading volumes are managed through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S. Husky is able to capture price differences between the two markets by utilizing infrastructure capacity to deliver production and/or third-party commodity trading volumes from Canada to the U.S. market.

- The Oil Sands business includes the exploration for, and development and production of, bitumen within Husky's 50 percent owned and operated Sunrise Energy project in the Athabasca region of northern Alberta (the "Sunrise Energy Project"). It also includes the marketing and transportation of Husky's and third-party production of bitumen through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S.

- The Western Canada Production business includes the exploration for, and development and production of, light crude oil, conventional natural gas and NGLs in Western Canada. Husky's conventional natural gas and NGL production is marketed and transported with other third-party commodity trading volumes through access to capacity on third-party pipelines, export terminals and storage facilities which provides flexibility for market access.

- The U.S. Refining business includes the refining of crude oil at the crude oil refinery owned and operated by Husky and located in Lima, Ohio (the "Lima Refinery"), a non-operated interest in a crude oil refinery 50 percent owned by Husky and 50 percent owned and operated by BP Corporation North America Inc. ("BP") and located in Toledo, Ohio (the "BP-Husky Toledo Refinery"), and the crude oil refinery owned by Husky and located in Superior, Wisconsin (the "Superior Refinery") to produce diesel fuel, gasoline, asphalt and other products. Husky also markets its own and third-party volumes of refined petroleum products including gasoline and diesel fuel.

- The Canadian Refined Products business includes the marketing of Husky's and third-party volumes of refined petroleum products, including gasoline and diesel, through petroleum outlets.

Offshore

Husky's Offshore business includes operations, development and exploration in Asia Pacific and Atlantic. The price received for Husky's Asia Pacific production is largely based on long-term contracts and crude oil production from Atlantic is primarily driven by the price of Brent.

Additional information concerning Husky's business as of December 31, 2020 may be found in the Husky AIF, which is filed and available on SEDAR under Husky's profile at sedar.com and on EDGAR at sec.gov.

INTEGRATED CORRIDOR

Third-Party Pipeline Commitments

In 2010, Husky commenced its pipeline commitment on the Keystone pipeline system, which ships Canadian crude oil from Hardisty, Alberta to Patoka, Illinois. Husky has the ability to utilize the portion of the Keystone pipeline system that continues to Cushing, Oklahoma, and Husky holds long-term firm capacity on the Enbridge Flanagan South pipeline and Southern Access Extension pipeline which connect Enbridge's Mainline to the U.S. Gulf Coast and Patoka markets.

Due to Husky's Keystone pipeline commitment, the Lima Refinery has the ability to access a significant amount of Canadian crude oil as part of its crude feedstock requirements. The Keystone pipeline has enabled Husky to transport crude oil through interconnecting pipeline systems to the Lima Refinery and/or sell it into the Cushing, Oklahoma market.

In 2017, Husky purchased the 50,000 barrel per-day Superior Refinery, which runs a combination of heavy Canadian crude and light crudes from Canada and the U.S. The Superior Refinery is located on the Enbridge Mainline crude system. As a seller and buyer of crude oils, Husky has a relatively balanced exposure to many location and grade differentials.

Lloydminster Heavy Oil Value Chain

Thermal and Non-Thermal Developments

Heavy Oil and Bitumen

The majority of Husky's heavy oil assets are located in the Lloydminster region of Alberta and Saskatchewan, with lands consisting of approximately two million acres. The majority of Husky's operations are 100 percent working interest. Husky's operations are supported by a network of facilities and pipelines that transport heavy crude oil and bitumen from Husky's field locations to the Lloydminster Asphalt Refinery, Lloydminster Upgrader and Husky's other assets in the Integrated Corridor, providing Husky full integration.

Lloydminster Thermal Projects

Husky's Lloydminster bitumen production consists of eleven thermal plants located in the Lloydminster region of Saskatchewan: Bolney/Celtic, Dee Valley, Edam East, Edam West, Paradise Hill, Pikes Peak South, Rush Lake 1 & 2, Sandall, Spruce Lake Central and Vawn. Each plant has a number of production pads and utilizes SAGD technology. Husky's Lloydminster thermal production has been ramped up to full rates following a deliberate ramp down late in the first quarter of 2020 in response to market conditions. Production from Husky's Lloydminster thermal projects averaged 81,000 barrels per day in 2020.

Husky has an inventory of thermal projects. These long-life developments are built with modular, repeatable designs and require low sustaining capital once brought online.

Tucker Thermal Project

Husky's Tucker thermal project (the "Tucker Thermal Project") is a SAGD oil sands project located 30 kilometers northwest of Cold Lake, Alberta. It commenced bitumen production at the end of 2006.

Bitumen production averaged 18,300 barrels per day in 2020.

A major plant turnaround was completed for the central processing facility and field in 2020.

Cold and Enhanced Oil Recovery ("EOR")

Husky's production from its Cold and EOR business consists of a combination of production technologies including, cold heavy oil productions with sand ("CHOPS") and horizontal wells and EOR projects.

During 2020, Husky operated three CO2 injection EOR pilot projects and a CO2 capture and liquefaction plant at the Lloydminster Ethanol Plant. The liquefied CO2 is used in the ongoing EOR piloting program. Husky is also piloting a CO2 capture technology at its Pikes Peak South facility in Saskatchewan.

Production averaged 21,400 barrels per day of heavy crude oil, 1,400 barrels per day of medium crude oil and 11.2 million cubic feet per day of conventional natural gas in 2020.

Upgrading Operations

Husky owns and operates the Lloydminster Upgrader. The Lloydminster Upgrader is designed to process blended heavy crude oil feedstock, creating high quality, low-sulphur synthetic crude oil and ultra-low sulphur diesel and recovers diluent from the feedstock for return to, and reuse in, the field. Synthetic crude oil is used as refinery feedstock for the production of transportation fuels in Canada and the U.S.

The Lloydminster Upgrader's current rated production capacity is 81,500 barrels per day of synthetic crude oil, diluent and ultra-low sulphur diesel.

Production at the Lloydminster Upgrader averaged 45,872 barrels per day of synthetic crude oil, 11,926 barrels per day of diluent and 6,043 barrels per day of ultra-low sulphur diesel in 2020. In addition, as by-products of its upgrading operations, the Lloydminster Upgrader produced approximately 297 long ton per day of sulphur and 774 long ton per day of petroleum coke during 2020. These products are sold in Canadian and international markets.

Lloydminster Asphalt Refinery

The Lloydminster Asphalt Refinery processes heavy crude oil and bitumen into asphalt products used in road construction and maintenance. The refinery has a throughput capacity of 30,000 barrels per day of heavy crude oil and bitumen. The refinery also produces straight run gasoline, bulk distillates and industrial products. The straight run gasoline stream

is removed and re-circulated into HMLP's pipeline network as pipeline diluent. The distillate stream is transferred to the Lloydminster Upgrader and treated for blending into the Husky Synthetic Blend ("HSB") stream. Industrial products are a blend of medium and light distillate and gas oil streams, which are typically sold directly to customers as refinery feedstock, drilling and well-fracturing fluids, or used in asphalt cutbacks and emulsions.

Refinery throughput averaged 28,000 barrels per day of blended heavy crude oil and bitumen feedstock in 2020. Due to the seasonal demand for asphalt products, many asphalt refineries typically operate at full capacity only during the normal paving season in Canada and the northern U.S. Husky has implemented various strategies to increase refinery throughput during the other months of the year that are outside of the normal paving season, such as increasing storage capacity and developing U.S. markets for asphalt products. This allows the Lloydminster Asphalt Refinery to run at or near full capacity throughout the year.

Asphalt Distribution Network

In addition to sales directly from the Lloydminster Asphalt Refinery, Husky, through its asphalt division, has an asphalt distribution network which consists of seven asphalt terminals located at: Kamloops, British Columbia; Edmonton and Lethbridge, Alberta; Yorkton, Saskatchewan; Winnipeg, Manitoba; Rhinelander, Wisconsin; and Crookston, Minnesota and an emulsion plant located at Saskatoon, Saskatchewan. Husky also markets asphalt from independently operated terminals in the states of Washington, Minnesota, Wisconsin and Ohio.

The asphalt terminals in Rhinelander, Wisconsin and Crookston, Minnesota and the independently operated terminals in the states of Washington, Minnesota, Wisconsin and Ohio are part of Husky's U.S. Refining business segment.

Ethanol Plants

Husky's ethanol plant in Lloydminster, Saskatchewan has an annual nameplate capacity of 130 million liters and its Minnedosa, Manitoba ethanol plant has an annual nameplate capacity of 130 million liters. Combined ethanol production averaged 733,000 liters per day in 2020.

During 2012, the Lloydminster plant commissioned a CO2 capture facility. The plant is currently capturing CO2 for use in Husky's non-thermal EOR projects and ethanol produced at the plant has a low carbon intensity designation.

Husky Midstream Limited Partnership

HMLP was created in July 2016 with the sale of selected pipeline gathering systems in Alberta and Saskatchewan and the Lloydminster and Hardisty terminals. CKI Infrastructure Holdings Limited owns 16.25 percent, Power Assets Holdings Limited owns 48.75 percent and Husky owns 35 percent of HMLP and Husky is the operator. HMLP has approximately 2,200 kilometers of pipeline in the Lloydminster region, 5.9 million barrels of storage capacity at Hardisty and Lloydminster and other ancillary assets.

Husky's Lloydminster terminal, with a total storage capacity of 1.0 million barrels, serves as a hub for the gathering systems. The pipeline systems transport blended heavy crude oil to Lloydminster, accessing markets through the Lloydminster Upgrader and Lloydminster Asphalt Refinery. Blended heavy crude oil and bitumen from the field and synthetic crude oil from the upgrading operations are transported south to Hardisty, Alberta to a connection with the major export trunk pipelines. Husky's Hardisty terminal, with a total storage capacity of 4.9 million barrels, acts as the exclusive blending hub for WCS. HMLP has diversified its operations with its Ansell Corser gas processing plant in west-central Alberta, with 120 million cubic feet per day of processing capacity.

Oil Sands

Sunrise Energy Project

On March 31, 2008, Husky and BP completed a transaction that created integrated North American oil sands and refining businesses. The businesses are comprised of a 50/50 partnership to develop the Sunrise Energy Project, operated by Husky, and a 50/50 limited liability company for the BP-Husky Toledo Refinery, operated by BP Products North America Inc.

The Sunrise Energy Project is a SAGD oil sands project located in the Athabasca region of northern Alberta. Bitumen production averaged approximately 44,800 barrels per day (22,400 barrels per day Husky working interest) in 2020.

Tucker Thermal Project

The Tucker Thermal Project is a SAGD oil sands project reported within the Lloydminster Heavy Oil Value Chain. See "Lloydminster Heavy Oil Value Chain - Thermal and Non-Thermal Developments" for more information.

Western Canada Production

Northern Operations

Husky's Northern Operations are located primarily in northwest Alberta. Production in 2020 consisted of approximately 1,176 barrels per day of light crude oil, 5,208 barrels per day of NGLs and 148.2 million cubic feet per day of conventional natural gas reflecting heavily weighted conventional natural gas production of approximately 79 percent. Primary areas of operations include Edson and Grande Prairie, where operations are centered on liquids-rich gas resource production.

Edson operations are located primarily in west-central Alberta and consist of the Ansell and Galloway areas. The Ansell natural gas resource play is located in the deep basin Cretaceous formations. Husky holds an average 95 percent working interest in approximately 177 net sections of contiguous lands. Production from the Ansell and Galloway areas has doubled since 2012 and averaged 1,420 barrels per day of NGL and 100.1 million cubic feet per day of conventional natural gas in 2020.

Grande Prairie operations are located primarily in northwest Alberta and consist primarily of the

Wembley, Kakwa, and Wapiti areas. Production from Grande Prairie averaged 1,170 barrels per day of light crude oil, 3,794 barrels per day of NGLs and 48.1 million cubic feet per day of conventional natural gas in 2020. The Kakwa Spirit River liquids-rich natural gas resource play averaged 36 barrels per day of light crude oil, 1,861 barrels per day of NGLs and 27.8 million cubic feet per day of conventional natural gas in 2020. Wapiti averaged 976 barrels per day of NGLs and 3.8 million cubic feet per day of conventional natural gas in 2020.

Southern Operations

Husky's Southern Operations are primarily located in central and southern Alberta. As at December 31, 2020, Husky operated three natural gas facilities with approximately 600 active wells throughout the area. Production from Southern Operations averaged 265 barrels per day of light crude oil, 1,500 barrels per day of NGLs and 23.1 million cubic feet per day of conventional natural gas in 2020.

Rainbow Lake Operations

Rainbow Lake, located approximately 900 kilometers northwest of Edmonton, Alberta, is the site of Husky's largest light crude oil production operation in Western Canada. Production from the Rainbow Lake assets averaged 4,286 barrels per day of light crude oil, 3,500 barrels per day of NGL and 78.7 million cubic feet per day of conventional natural gas in 2020.

Husky holds a 50 percent interest in a 90 megawatt natural gas fired cogeneration facility adjacent to its Rainbow Lake processing plant.

Canadian Refined Products

Retail and Commercial Network

As of December 31, 2020, Husky's retail and commercial network included 546 independently operated Husky and Esso-branded petroleum product outlets. Husky's retail and commercial operating model is balanced by corporate-owned/dealer-operated and branded dealer-owned-and-operated sites. The network consists of a variety of full- and self-serve retail stations, travel centres and cardlocks serving urban and rural markets across the country, while Husky's bulk distributors offer direct sales to commercial and agricultural markets in the Prairie provinces.

U.S. Refining

Lima Refinery

The Lima Refinery has a crude oil throughput capacity of up to 175,000 barrels per day. The Lima Refinery processes both light sweet crude oil and heavy crude oil feedstock sourced from the U.S. and Canada, which includes Canadian synthetic crude oil, including HSB produced by the Lloydminster Upgrader. The Lima Refinery produces low-sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, jet fuel, petrochemical feedstock and other by-products. The feedstocks are received via the Mid-Valley and Marathon pipelines, and the refined products are transported via the Buckeye, Inland and Energy Transfer Partners pipeline systems and by rail car to primary markets in Ohio, Illinois, Indiana, Pennsylvania and southern Michigan.

During 2020, total throughput at the Lima Refinery averaged 140,000 barrels per day. Production consisted of an average of 68,000 barrels per day of gasoline, 53,000 barrels per day of total distillates and 19,000 barrels per day of other products in 2020.

The refinery is designed to allow for the processing of up to 40,000 barrels per day of heavy crude oil from Western Canada and the ability to swing between light and heavy crude oil feedstock.

BP-Husky Toledo Refinery

Husky's BP-Husky Toledo Refinery has a nameplate capacity of 160,000 barrels per day. Products from the refinery include low-sulphur gasoline, ultra-low sulphur diesel, aviation fuels and by-products.

Husky's share of total throughput averaged 65,400 barrels per day in 2020, with Husky's share of sales averaging 38,900 barrels per day of gasoline, 20,100 barrels per day of distillates and 9,600 barrels per day of other fuel and feedstock.

Superior Refinery

On November 8, 2017, Husky completed the acquisition of the Superior Refinery, which has a permitted throughput capacity of 50,000 barrels per day and an operating capacity of 49,000 barrels per day on its crude slate at the time of acquisition. The refinery produces motor fuel products and asphalt from light and heavy crude oil originating from North Dakota and Western Canada.

The refinery also has associated infrastructure including five storage and distribution terminals that are strategically located throughout the northern area of the U.S. These terminals include: the Superior products terminal; the Duluth Terminal in Duluth, Minnesota, which has a storage capacity of 200,000 barrels; the Duluth Marine Terminal in Duluth, Minnesota which has a storage capacity of 14,000 barrels; the Rhinelander Terminal in Rhinelander, Wisconsin, which has a storage capacity of 166,000 barrels; and the Crookston Terminal in Crookston, Minnesota, which has a storage capacity of 156,000 barrels.

On April 26, 2018, the Superior Refinery experienced an incident while preparing for a major turnaround and was taken out of operation. During 2019, demolition, site preparation work and permitting were completed, and the rebuild work commenced. The rebuild is ongoing and Cenovus anticipates a substantial portion of the investment will be recovered from property damage insurance.

OFFSHORE

Asia Pacific

China

Liwan Gas Project

The Liwan Gas Project includes the natural gas discoveries at the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields within the Contract Area 29/26

exploration block located in the Pearl River Mouth Basin of the South China Sea, approximately 300 kilometers southeast of the Hong Kong Special Administrative Region.

Husky has a 49 percent working interest in the Liwan 3-1 and Liuhua 34-2 fields and a 75 percent working interest in the Liuhua 29-1 field, and China National Offshore Oil Corporation Limited or its subsidiaries ("CNOOC") has 51 percent and 25 percent working interests, respectively.

Construction work was completed in the third quarter of 2020 at Liuhua 29-1, the third deepwater gas field of the Liwan Gas Project. First gas production from the Liuhua 29-1 development started in November 2020 and sales were initiated that same month. This seven-well subsea development is fully installed and utilizes the existing Liwan Gas Gathering system and the facilities located on the central platform and Gaolan Onshore Gas Plant. The buyer began taking 40 million cubic feet per day on November 4, 2020.

Total gas sales from Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 averaged 366 million cubic feet per day, 34 million cubic feet per day and 6 million cubic feet per day, respectively in 2020. Husky's working interest share of production from the three fields was 201 million cubic feet per day of conventional natural gas and 8,600 barrels per day of NGL in 2020.

Block 15/33

Husky executed a production sharing contract ("PSC") in December 2015 for an exploration block offshore China. Block 15/33 is located in the Pearl River Mouth Basin in the South China Sea, about 140 kilometers southeast of the Hong Kong Special Administrative Region and covers an area of 155 square kilometers in water depths of approximately 80 to 100 meters. Husky is the operator of the block during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, its partner CNOOC may assume a working interest of up to 51 percent during the development and production phase by paying its proportional share of all development costs. Under the PSC, the corresponding CNOOC share of exploration costs is to be recovered from production allocated to Husky.

In the third quarter of 2020, an agreement was signed between Husky and CNOOC to extend the end of the second phase of exploration period of the petroleum contract to December 31, 2021.

Block 16/25

Husky executed a PSC in April 2017 for an exploration block offshore China. Block 16/25 is located in the Pearl River Mouth Basin in the South China Sea, about 150 kilometers southeast of the Hong Kong Special Administrative Region and approximately 72 kilometers northeast of Block 15/33. The block covers an area of 44 square kilometers in water depths of approximately 85 to 100 meters.

During 2020, an amendment agreement was signed between Husky and CNOOC under which the first phase of the exploration period was extended to April 30, 2022, with the remaining obligatory exploration well to be completed in the area to be agreed upon by the parties. The initial contract area under the Block 16/25 petroleum contract was relinquished pursuant to the terms of the amendment agreement.

Blocks 22/11 and 23/07

Husky and CNOOC signed two PSCs for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea in the first half of 2018. Husky is the operator of both blocks with a working interest of 100 percent during the exploration phase. In the event of a commercial discovery, its partner CNOOC may assume a participating partnership interest of up to 51 percent in either or both blocks for the development and production phases. Husky entered into the two-year exploration phase II of the PSC for Block 23/07 and committed to drill one exploration well before November 30, 2021. Block 22/11 was relinquished during 2020.

Taiwan

In December 2012, Husky signed a joint venture agreement with CPC Corporation, the Taiwan national oil and gas company. Husky and CPC Corporation have rights to an exploration block in the South China Sea covering approximately 7,700 square kilometers located southwest of the island of Taiwan. Husky holds a 75 percent working interest during exploration, while CPC Corporation holds the remaining 25 percent and has the right to participate in any development programs up to a 50 percent interest.

Indonesia

Madura Strait

Husky has a 40 percent interest in the joint venture that holds the Madura Strait PSC encompassing approximately 622,000 acres (2,516 square kilometers) in the Madura Strait area, located offshore East Java, Indonesia. Husky's two partners in the incorporated joint venture are CNOOC, which is the contracted operator and has a 40 percent working interest, and Samudra Energy Ltd., which holds the remaining 20 percent interest through its affiliate, SMS Development Ltd. The Madura Strait includes the operating BD field and future developments at the MDA, MBH, MDK and MAC fields.

Total BD field sales averaged 86 million cubic feet per day of gas and 6,000 barrels per day of associated liquids in 2020. Husky's working interest share of production was 34 million cubic feet per day of conventional natural gas and 2,400 barrels per day of NGLs in 2020.

Atlantic

Husky's Atlantic exploration and development program is focused in the Jeanne d'Arc Basin and the Flemish Pass offshore Newfoundland and Labrador ("NL"). The Jeanne d'Arc Basin contains the Hibernia, Terra Nova and Hebron fields, as well as the White Rose field and satellite extensions, including North Amethyst, West White Rose and South White Rose. In the Flemish Pass Basin, Husky holds a 35 percent non-operated working interest in each of the Bay

du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. Husky is the operator of the White Rose field and satellite extensions and holds an ownership interest in the Terra Nova field, as well as a number of smaller undeveloped fields. Husky also holds significant exploration acreage offshore NL.

The White Rose field is located 354 kilometers off the coast of NL and is approximately 48 kilometers east of the Hibernia field on the eastern flank of the Jeanne d'Arc Basin. Husky is the operator of the main White Rose field and satellite tiebacks, including the North Amethyst, West White Rose and South White Rose extensions. Husky has a 72.5 percent working interest in the main field and a 68.875 percent working interest in the satellite extensions. To date, production has been facilitated via subsea tie-ins with wells drilled independently through drill centres and connected via flowlines to the SeaRose floating production, storage and offloading vessel.

Husky's share of light crude oil production from the White Rose field and satellite extensions was 17,600 barrels per day (Husky working interest) during 2020.

In May 2017, Husky and its co-venturers announced plans to proceed with full field development at West White Rose using a fixed drilling platform. Major construction was suspended in March 2020 due to the COVID-19 situation. In October 2020, Husky announced the continued suspension of construction on the Concrete Gravity Structure in Argentia, NL.

DESCRIPTION OF THE BUSINESS FOLLOWING THE HUSKY ARRANGEMENT

Management is in the process of finalizing the determination of the operating and reporting segments for the Corporation following the Husky Arrangement. It is anticipated that the Corporation's business will be conducted predominately through an upstream and downstream segment. Management continues to evaluate how the segments may be presented and will make a final determination during the first quarter of 2021.

The upstream business is anticipated to be reported as follows:

- Oil Sands, includes the development and production of heavy oil and bitumen in northeast Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Christina Lake, Sunrise and Tucker oil sands projects, as well as Lloydminster Thermal and Cold and Enhanced Oil Recovery assets.
- Conventional, includes the operations from conventional oil and natural gas production, including processing operations in the Deep Basin and other parts of Western Canada.
- Offshore, includes the offshore operations, exploration and development activities in the Asia Pacific region and Atlantic Canada region.

The downstream business is anticipated to be reported as follows:

- Canadian Manufacturing, includes Cenovus's owned and operated upgrader and asphalt refinery in Lloydminster, the owned and operated crude-by-rail terminal and two ethanol plants.
- Retail, includes the Canadian retail, commercial and wholesale channels.
- U.S. Manufacturing, includes the U.S. operations of wholly-owned refineries in Lima and Superior, the jointly owned Wood River and Borger refineries with operator Phillips 66 and the jointly owned Toledo refinery with BP Products North America Inc. as operator.

COMPETITIVE CONDITIONS

All aspects of the energy industry are highly competitive. For further information on the competitive conditions affecting Cenovus, refer to the section entitled "Risk Management and Risk Factors – Operational Risk" in the Corporation's annual 2020 MD&A, which section of the MD&A is incorporated by reference into this AIF.

ENVIRONMENTAL PROTECTION

All phases of crude oil, natural gas and refining operations are subject to environmental regulation pursuant to a variety of federal, provincial, territorial, state, municipal and local laws and regulations in the jurisdictions in which Cenovus operates, as well as international conventions (collectively, the "environmental regulations"). For further information on the environmental regulations affecting Cenovus, refer to the section entitled "Risk Management and Risk Factors – Environmental Risk" in the Corporation's annual 2020 MD&A, which section of the MD&A is incorporated by reference into this AIF.

CODE OF BUSINESS CONDUCT & ETHICS

Cenovus has established policies and standards relating to the conduct of business in a safe, healthy, ethical, legal and environmentally, socially and fiscally responsible manner. Cenovus's commitment in these areas is reflected in the Code of Business Conduct & Ethics (the "Code"). The Code applies to the Corporation's directors, officers and all employees, as well as contractors and suppliers who conduct activities for, or on behalf of, Cenovus. Individuals subject to the Code are accountable for applying it to their own conduct and work. Each employee, officer and director is also asked to regularly review the Code to confirm they understand their individual responsibilities and that they conform to the requirements of the Code.

The Code addresses the identification and management of ethical situations and provides guidance in making ethical business decisions and reporting violations of the Code. The Code provides a message from the President & Chief Executive Officer and addresses a number of matters including: (a) Cenovus's values and reputation; (b) responsible information use; (c) acting with integrity;

(d) compliance with laws and regulations; and (e) reporting potential violations.

Sustainability Policy

Cenovus's Sustainability Policy addresses business conduct to help ensure the Corporation's activities are undertaken in a responsible, transparent and respectful manner and in compliance with all applicable laws, regulations and industry standards in the jurisdictions in which Cenovus operates. The Sustainability Policy specifically references the following matters: (a) leadership and governance; (b) people; (c) environment; (d) stakeholder engagement; (e) Indigenous engagement; and (f) community involvement and investment.

With respect to the environment specifically, the Sustainability Policy provides that Cenovus recognizes the importance of: integrating environmental considerations into Cenovus's business plans, spending decisions, performance management, project development, operations, communications and stakeholder relations; tracking and reporting on a broad range of environmental metrics; and committing to limit Cenovus's impact on climate, air, land and water by investing in technology, continuously improving operating practices and collaborating externally to find innovative solutions to minimize environmental impact and maximize business value.

With respect to social aspects, the Sustainability Policy provides that Cenovus recognizes the importance of: conducting its business with respect and care for the people and communities affected by its activities, noting the Corporation's commitment to health and safety and support for the principles of the Universal Declaration of Human Rights; engaging stakeholders, including Indigenous communities, in a manner based on honesty, trust and respect; and developing and maintaining positive relationships with the communities within which Cenovus operates by, among other means, providing opportunities that help neighbouring communities share in the benefits that come from responsibly developing oil and natural gas resources, and striving to create a positive impact for both the community and Cenovus's business through community investment programs.

In addition to the Code and Sustainability Policy, Cenovus has established other policies and practices that in some instances relate to environmental and or social aspects of Cenovus's business. Stakeholders, employees and contractors are encouraged to report any business conduct concerns, including violations of applicable laws or any Cenovus policy, through the Corporation's anonymous Integrity Helpline. Employees and contractors may also report any such concerns to their supervisor, a human resources business partner, or a member of the Investigations Committee.

The aforementioned policies are accessible on the Corporation's website at cenovus.com, as is Cenovus's Environmental, Social & Governance Report ("ESG Report"). The ESG Report is published annually to detail management's efforts and performance across environment, social and governance topics that are important to its stakeholders.

EMPLOYEES

The following table summarizes Cenovus's full-time equivalent ("FTE") employees as at December 31, 2020:

	FTE Employees
Upstream	1,415
Downstream	109
Corporate	889
Total	2,413

Cenovus also engages contractors and service providers. As of December 31, 2020, Husky had 4,598 FTE employees. Refer to the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2020 MD&A, which section of the MD&A is incorporated by reference into this AIF, for further information on employee and other workforce related risks affecting Cenovus.

RISK FACTORS

A discussion of risk factors can be found in the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2020 MD&A, which section of the MD&A is incorporated by reference into this AIF.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

As a Canadian issuer, Cenovus is subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of the Corporation's reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

As at December 31, 2020, the Corporation's reserves were located in Alberta and British Columbia, Canada. Cenovus retained two independent qualified reserves evaluators ("IQREs"), McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Ltd. ("GLJ"), to evaluate and prepare reports on 100 percent of its bitumen, heavy crude oil, light crude oil and medium crude oil combined ("light and medium oil"), NGLs, conventional natural gas and shale gas proved and probable reserves. McDaniel evaluated approximately 96 percent of Cenovus's proved reserves, all located in Alberta, and GLJ evaluated approximately four percent of the Corporation's proved reserves, located in Alberta and British Columbia.

The Safety, Environment, Responsibility and Reserves Committee ("SERR Committee"), composed entirely of independent directors, reviews, among other things, the qualifications and appointment of the IQREs, the procedures relating to the disclosure of information with respect to oil and gas activities and the procedures for providing information to the IQREs. The SERR Committee meets independently with the management of Cenovus and each IQRE to determine whether any restrictions affect the ability of the IQREs to report on the reserves data without reservation. In addition, the SERR Committee reviews the reserves data and the report of the IQREs and provides a recommendation regarding approval of the reserves disclosure to the Board.

Classifications of reserves as proved or probable are only attempts to define the degree of certainty associated with the estimates. There are numerous uncertainties inherent in estimating quantities of petroleum 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 costs assumptions will be attained and variances could be material. Readers should review the definitions and information contained in "Additional Notes to Reserves Data Tables", "Definitions" and "Pricing Assumptions" in conjunction with the reserves disclosure. The 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 disclosed. See the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2020 MD&A, which section of the MD&A is incorporated by reference into this AIF, for additional information.

Cenovus's reserves data and other oil and gas information contained in this AIF is dated February 8, 2021, with an effective date of December 31, 2020. McDaniel's preparation date of the information is January 19, 2021 and GLJ's preparation date is January 6, 2021. For certain reserves data, additional disclosure is provided to show the anticipated effect of the Husky Arrangement – see "Expected Changes to Reserves - Husky Arrangement". For certain categories of "Other Oil and Gas Information" additional disclosure is provided to show the anticipated effect of the Husky Arrangement, which disclosure is identified as including information from Husky. Additional information concerning Husky and its reserves data and other oil and gas information as of December 31, 2020 may be found in the Husky AIF and the Husky MD&A, each of which is filed and available on SEDAR under Husky's profile at sedar.com and on EDGAR at sec.gov.

DISCLOSURE OF RESERVES DATA

The reserves data presented summarizes the Corporation's bitumen, heavy crude oil, light and medium oil, NGLs, conventional natural gas, shale gas and total reserves and the net present values ("NPV") and future net revenue ("FNR") for these reserves. The reserves data uses forecast prices and costs prior to provision for interest, G&A expenses or the impact of any hedging activities. Estimates of FNR have been presented on a before and after income tax basis. For the purposes of this section and the section entitled "Expected Changes to Reserves – Husky Arrangement", references to "Company" are to Cenovus Energy Inc.

Summary of Company Interest Oil and Gas Reserves as at December 31, 2020
(Forecast prices and costs)

Before Royalties[1]	Bitumen (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas[2] (Bcf)	Total (MMBOE)
Proved Reserves					
Developed Producing	765	7	40	790	943
Developed Non-Producing	199	-	1	18	203
Undeveloped	3,848	-	9	157	3,884
Proved Reserves	4,812	7	50	965	5,030
Probable Reserves	1,520	6	31	601	1,656
Proved plus Probable Reserves	6,332	13	81	1,566	6,686

After Royalties[3]	Bitumen[4] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas[2] (Bcf)	Total (MMBOE)
Proved Reserves					
Developed Producing	604	6	33	745	768
Developed Non-Producing	156	-	1	17	160
Undeveloped	2,999	-	8	149	3,032
Proved Reserves	3,759	6	42	911	3,960
Probable Reserves	1,115	5	27	561	1,240
Proved plus Probable Reserves	4,874	11	69	1,472	5,200

(1) Before royalties excludes royalty interest reserves.
(2) Includes shale gas that is not material representing less than 1% of total conventional natural gas on a proved plus probable basis.
(3) Includes royalty interest reserves.
(4) Includes heavy crude oil that is not material representing less than 1% of total bitumen on a proved plus probable basis.

Summary of Net Present Value of Future Net Revenue as at December 31, 2020

(Forecast prices and costs)

	Discounted at %/year ($ millions)					Unit Value Discounted at 10%(1)
Before Income Taxes	0%	5%	10%	15%	20%	$/BOE
Proved Reserves						
Developed Producing	11,486	12,182	10,814	9,517	8,464	14.09
Developed Non-Producing	4,215	3,155	2,440	1,938	1,572	15.30
Undeveloped	83,708	30,790	14,080	7,530	4,478	4.64
Proved Reserves	99,409	46,127	27,334	18,985	14,514	6.90
Probable Reserves	46,804	11,424	4,576	2,621	1,807	3.69
Proved plus Probable Reserves	146,213	57,551	31,910	21,606	16,321	6.14

	Discounted at %/year ($ millions)				
After Income Taxes(2)	0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	9,143	10,201	9,229	8,196	7,333
Developed Non-Producing	3,267	2,437	1,880	1,490	1,208
Undeveloped	64,765	23,546	10,578	5,550	3,230
Proved Reserves	77,175	36,184	21,687	15,236	11,771
Probable Reserves	36,095	8,724	3,488	1,999	1,377
Proved plus Probable Reserves	113,270	44,908	25,175	17,235	13,148

(1) Unit values have been calculated using Company Interest After Royalties reserves.
(2) Values are calculated by considering existing tax pools and tax circumstances for Cenovus and its subsidiaries in the consolidated evaluation of Cenovus's oil and gas properties and taking into account current federal and provincial tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see Cenovus's Consolidated Financial Statements and MD&A for the year ended December 31, 2020.

Total Future Net Revenue (undiscounted) as at December 31, 2020

(Forecast prices and costs - $ millions)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Total Abandonment and Reclamation Costs(1)	Future Net Revenue Before Future Income Taxes	Future Income Taxes	Future Net Revenue After Future Income Taxes
Proved Reserves	258,732	57,269	62,975	32,576	6,503	99,409	22,234	77,175
Proved plus Probable Reserves	372,906	86,837	84,905	47,597	7,354	146,213	32,943	113,270

(1) Total abandonment and reclamation costs included for all wells, facilities and other liabilities, known and existing, and to be incurred as a result of future development activity.

Future Net Revenue by Product Type as at December 31, 2020

(Forecast prices and costs)

Reserves Category	Product Types	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($ millions)	Unit Value Discounted at 10%/year(1) ($/BOE)
Proved Reserves	Bitumen(2)	26,834	7.14
	Light and Medium Oil(3)	60	4.61
	Conventional Natural Gas(4)	440	2.34
	Total	27,334	6.90
Proved plus Probable Reserves	Bitumen(2)	30,863	6.33
	Light and Medium Oil(3)	124	4.87
	Conventional Natural Gas(4)	923	3.07
	Total	31,910	6.14

(1) Unit values have been calculated using Company Interest After Royalties reserves.
(2) Includes heavy crude oil that is not material.
(3) Includes solution gas and other byproducts.
(4) Includes shale gas and other byproducts, but excludes solution gas.

Additional Notes to Reserves Data Tables

- The estimates of FNR presented do not represent fair market value.
- FNR from reserves excludes cash flows related to Cenovus's risk management activities.
- For disclosure purposes, Cenovus has included heavy crude oil with bitumen and shale gas with conventional natural gas, as the reserves of heavy crude oil and shale gas are not material.
- In accordance with NI 51-101, NPV and FNR amounts presented include all of Cenovus's existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.
- Barrels of oil equivalent estimates and tables may not sum due to rounding.

Definitions

1. **After Royalties** means volumes after deduction of royalties and includes royalty interest reserves.
2. **Before Royalties** means volumes before deduction of royalties and excludes royalty interest reserves.
3. **Company Interest** means, in relation to production, reserves, resources and property, the interest (operating or non-operating) held by Cenovus.
4. **Gross** means: (a) in relation to wells, the total number of wells in which Cenovus has an interest; and (b) in relation to properties, the total acreage of properties in which Cenovus has an interest.
5. **Net** means: (a) in relation to wells, the number of wells obtained by aggregating Cenovus's working interest in each of its gross wells; and (b) in relation to Cenovus's interest in a property, the total acreage in which it has an interest multiplied by its working interest.
6. **Proved plus probable reserves life index** means Company Interest Before Royalties proved plus probable reserves divided by Company Interest Before Royalties production.
7. **Reserves** are estimated remaining quantities of crude oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions, which are generally accepted as being reasonable, and are disclosed later in this AIF.

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

- **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.
- **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.

Each of the reserves categories may be divided into developed and undeveloped categories:

- **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided as follows:
  - **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.
  - **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.
- **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Pricing Assumptions

The forecast of prices, inflation and exchange rate provided in the table below is computed using the average of forecasts ("IQRE Average Forecast") by McDaniel, GLJ and Sproule Associates Limited ("Sproule") and is used to estimate FNR associated with the reserves disclosed herein. The IQRE Average Forecast is dated January 1, 2021. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs. For historical prices realized during 2020, see "Production History and Per-Unit Results" in this AIF.

	Oil and Liquids				Natural Gas		
Year	WTI Cushing Oklahoma (US$/bbl)	Edmonton Par Price 40 API (C$/bbl)	Western Canadian Select (C$/bbl)	Edmonton C5+ (C$/bbl)	AECO Gas Price (C$/MMBtu)	Inflation Rate (%/year)	Exchange Rate (US$/C$)
2021	47.17	55.76	44.63	59.24	2.78	0.0	0.7683
2022	50.17	59.89	48.18	63.19	2.70	1.3	0.7650
2023	53.17	63.48	52.10	67.34	2.61	2.0	0.7633
2024	54.97	65.76	54.10	69.77	2.65	2.0	0.7633
2025	56.07	67.13	55.19	71.18	2.70	2.0	0.7633
2026	57.19	68.53	56.29	72.61	2.76	2.0	0.7633
2027	58.34	69.95	57.42	74.07	2.81	2.0	0.7633
2028	59.50	71.40	58.57	75.56	2.86	2.0	0.7633
2029	60.69	72.88	59.74	77.08	2.92	2.0	0.7633
2030	61.91	74.34	60.93	78.62	2.98	2.0	0.7633
2031	63.15	75.83	62.15	80.19	3.04	2.0	0.7633
2032+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.7633

Future Development Costs

The following table outlines undiscounted future development costs deducted in the estimation of FNR for the years indicated:

Reserves Category ($ millions)	2021	2022	2023	2024	2025	Remainder	Total
Proved Reserves	340	457	886	821	630	29,442	32,576
Proved plus Probable Reserves	378	501	890	826	652	44,350	47,597

Cenovus believes that existing cash balances, internally generated cash flows, existing credit facilities, management of its asset portfolio and access to capital markets will be sufficient to fund the Corporation's future development costs. However, there can be no guarantee that the necessary funds will be available or that Cenovus will allocate funding to develop all of its reserves. Failure to develop those reserves would have a negative impact on the Corporation's FNR.

The interest or other costs of external funding are not included in the reserves and FNR estimates and would reduce FNR depending upon the funding sources utilized. Cenovus does not believe that interest or other funding costs would make development of any property uneconomic.

Reserves Reconciliation

The following tables provide a reconciliation of Company Interest Before Royalties reserves for bitumen, heavy crude oil, light and medium oil, NGLs, conventional natural gas and shale gas for the year ended December 31, 2020, presented using forecast prices and costs.

Proved	Bitumen[1] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas[2] (Bcf)	Total (MMBOE)
As at December 31, 2019	4,826	9	60	1,242	5,103
Extensions and Improved Recovery	4	-	1	10	6
Discoveries	-	-	-	-	-
Technical Revisions	131	-	(3)	(126)	108
Economic Factors	-	-	(2)	(37)	(9)
Acquisitions	-	-	1	18	3
Dispositions	(8)	-	-	-	(8)
Production[3]	(141)	(2)	(7)	(142)	(173)
As at December 31, 2020	4,812	7	50	965	5,030

Probable	Bitumen[1] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas[2] (Bcf)	Total (MMBOE)
As at December 31, 2019	1,594	8	37	783	1,768
Extensions and Improved Recovery	(4)	1	-	4	(2)
Discoveries	-	-	-	-	-
Technical Revisions	(50)	(2)	(4)	(155)	(83)
Economic Factors	-	(1)	(2)	(35)	(8)
Acquisitions	-	-	-	4	1
Dispositions	(20)	-	-	-	(20)
Production[3]	-	-	-	-	-
As at December 31, 2020	1,520	6	31	601	1,656

Proved plus Probable	Bitumen[1] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas[2] (Bcf)	Total (MMBOE)
As at December 31, 2019	6,420	17	97	2,025	6,871
Extensions and Improved Recovery	-	1	1	14	4
Discoveries	-	-	-	-	-
Technical Revisions	81	(2)	(7)	(281)	25
Economic Factors	-	(1)	(4)	(72)	(17)
Acquisitions	-	-	1	22	4
Dispositions	(28)	-	-	-	(28)
Production[3]	(141)	(2)	(7)	(142)	(173)
As at December 31, 2020	6,332	13	81	1,566	6,686

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.
(3) Production used for the reserves reconciliation differs from publicly reported production. In accordance with NI 51-101, Company Interest Before Royalties production used for the reserves reconciliation above includes Cenovus's share of gas volumes provided to FCCL for steam generation, but does not include royalty interest production.

Bitumen proved and proved plus probable reserves decreased by 14 million barrels and 88 million barrels, respectively, as additions from improved performance in Oil Sands were more than offset by the disposition of the Marten Hills heavy oil assets and current year production;

Light and medium oil proved and proved plus probable reserves decreased by two million barrels and four million barrels, respectively, as minor additions were more than offset by technical revisions attributed to updates to the Conventional development plan, economic factors due to reduced product pricing, and current year production;

NGLs proved and proved plus probable reserves decreased by 10 million barrels and 16 million barrels, respectively, as minor additions and a minor acquisition were more than offset by reductions due to technical revisions attributed to updates to the Conventional development plan, economic factors due to reduced product pricing, and current year production; and

Conventional natural gas proved and proved plus probable reserves decreased by 277 billion cubic feet and 459 billion cubic feet, respectively, as additions attributed to Conventional development and minor acquisitions were more than offset by reductions due to technical revisions attributed to updates to the Conventional development plan, economic factors due to reduced product pricing, and current year production.

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated by the IQREs in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook"). In general, undeveloped reserves are scheduled to be produced within the next one to 50 years.

The undeveloped tables presented here reflect the product type groups reported above, specifically, bitumen includes heavy crude oil and conventional natural gas includes shale gas.

Company Interest Proved Undeveloped – Before Royalties

	Bitumen(1) (MMbbls)		Light and Medium Oil (MMbbls)		NGLs (MMbbls)		Conventional Natural Gas(2) (Bcf)		Total (MMBOE)	
	First Attributed	Total at Year-End	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	197	3,986	1	1	7	15	159	324	233	4,056
2019	37	3,827	–	1	2	10	30	208	43	3,873
2020	99	3,848	–	–	1	9	16	157	103	3,884

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.

Company Interest Probable Undeveloped – Before Royalties

	Bitumen(1) (MMbbls)		Light and Medium Oil (MMbbls)		NGLs (MMbbls)		Conventional Natural Gas(2) (Bcf)		Total (MMBOE)	
	First Attributed	Total at Year-End	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	30	1,502	2	2	15	25	365	619	108	1,632
2019	7	1,474	3	5	5	21	87	433	29	1,571
2020	–	1,407	1	3	1	18	13	317	3	1,481

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.

DEVELOPMENT OF PROVED AND PROBABLE UNDEVELOPED RESERVES

Bitumen

At the end of 2020, Cenovus had proved undeveloped bitumen reserves of 3,848 million barrels Before Royalties, or approximately 80 percent of the Corporation's proved bitumen reserves. Of Cenovus's 1,520 million barrels of probable bitumen reserves, 1,407 million barrels, or approximately 93 percent, are undeveloped. The evaluation of these reserves anticipates that the reserves will be recovered using SAGD.

Typical SAGD project development involves the initial installation of a steam generation facility, at a cost much greater than drilling a production/injection well pair, and then progressively drilling sufficient SAGD well pairs to fully utilize the available steam.

Bitumen reserves can be classified as proved when there is sufficient stratigraphic drilling to have demonstrated to a high degree of certainty the presence of the bitumen in commercially recoverable volumes. McDaniel's standard for sufficient drilling in the McMurray formation is a minimum of eight stratigraphic wells per section with 3D seismic, or 16 stratigraphic wells per section with no seismic. Additionally, all requisite legal and regulatory approvals must have been obtained, operator funding approvals must be in place, and a reasonable development timetable must be established. Proved developed bitumen reserves are differentiated from proved undeveloped bitumen reserves by the presence of drilled production/injection well pairs at the reserves estimation effective date. Because a steam plant has a long life relative to well pairs, in the early stages of a SAGD project, only a small portion of proved reserves will be developed as the number of well pairs drilled will be limited by the available steam capacity.

Recognition of probable reserves requires sufficient drilling of stratigraphic wells to establish reservoir suitability for SAGD. McDaniel's standard for probable reserves is a minimum of four stratigraphic wells per section. Reserves will be classified as probable if the number of wells drilled falls between the stratigraphic well requirements for proved reserves and for probable reserves, or if the reserves are located outside of an approved development plan area, but within an approved project area. If reserves lie outside the approved development area, approval to include those reserves in the development area must be obtained before development drilling of SAGD well pairs can commence.

Development of the proved and probable Foster Creek and Christina Lake undeveloped reserves will take place in an orderly manner as additional well pairs are drilled to utilize the available steam when existing well pairs reach the end of their steam injection phase. Development and capital spending on the proved and probable undeveloped reserves at Narrows Lake continues with the project currently scheduled to be on stream by 2026. The forecast production of Cenovus's proved and proved plus probable bitumen reserves, extends approximately 46 years and 50 years, respectively. Production of the current proved developed portion is estimated to take approximately 21 years.

Light and Medium Oil, NGLs and Conventional Natural Gas

Cenovus's Conventional Assets proved undeveloped and proved plus probable undeveloped reserves are approximately one percent and two percent of the Corporation's proved and proved plus probable reserves, respectively. Cenovus plans to develop the Conventional proved and proved plus probable undeveloped reserves over the next five years and ten years, respectively.

SIGNIFICANT FACTORS OR UNCERTAINTIES AFFECTING RESERVES DATA

The evaluation of reserves is a continuous process that can be significantly impacted by a variety of internal and external influences. Revisions are often required resulting from changes in pricing, economic conditions, regulatory changes, and historical performance. While these factors can be considered and potentially anticipated, certain judgments and assumptions are always required. As new information becomes available, these areas are reviewed and revised accordingly. For a discussion of the risk factors and uncertainties affecting Cenovus's reserves data, see the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2020 MD&A, which section of the MD&A is incorporated by reference into this AIF. For a discussion of the risk factors and uncertainties affecting Husky's reserves data, see the section entitled "Risk Management and Risk Factors" in the Husky MD&A.

EXPECTED CHANGES TO RESERVES – HUSKY ARRANGEMENT

The *pro forma* reserves information presented in this AIF sets forth Cenovus's anticipated gross reserves as at December 31, 2020 after giving effect to the Husky Arrangement as though the transaction had occurred on December 31, 2020. Cenovus has not constructed a consolidated reserves report of the combined assets of Cenovus and Husky, and has not engaged an independent reserves evaluator to produce such a report in accordance with NI 51-101.

Cenovus and Husky employed different methodologies to estimate their reserves information for the year ended December 31, 2020. Cenovus retained two IQREs, McDaniel and GLJ, to evaluate and prepare reports on 100 percent of its proved and probable reserves. All of Husky's oil and gas reserves estimates were prepared by internal qualified reserves evaluators using a formalized process for determining, approving and booking reserves, and do not form part of Cenovus's reserves data as at December 31, 2020. For the purposes of Husky's NI 51-101 reserves disclosure in the Husky AIF, Husky engaged Sproule to conduct a complete audit and review of 100 percent of Husky's oil and gas reserves estimates. Sproule issued an audit opinion stating that Husky's internally generated proved and probable reserves and net present values based on forecast and constant price assumptions are, in aggregate, reasonable, and have been prepared in accordance with generally accepted oil and gas engineering and evaluation practices as set out in the COGE Handbook. Cenovus's Board has not independently reviewed Husky's process and procedures for determining, approving and booking Husky's reserves estimates and has relied on Sproule's audit opinion as to the reasonableness of Husky's reserves estimates as at December 31, 2020, and on Husky's review and approval of such audit.

As a result, the actual reserves of Cenovus (after giving effect to the Husky Arrangement), if calculated as at December 31, 2020 by an independent reserves evaluator in accordance with NI 51-101, may differ from the reserves information presented in this AIF for a number of reasons, and such differences may be material. Additional information concerning Husky's oil and natural gas properties and Husky's operations and business as of December 31, 2020 may be found in the Husky AIF and the Husky MD&A, each of which is filed and available on SEDAR under Husky's profile at sedar.com and on EDGAR at sec.gov.

Summary of Company Interest Oil and Gas Reserves as at December 31, 2020
(after giving effect to the Husky Arrangement)
(Forecast prices and costs)

Canada **Before Royalties**[1]	**Bitumen**[2] (MMbbls)	**Light and Medium Oil** (MMbbls)	**NGLs** (MMbbls)	**Conventional Natural Gas**[3] (Bcf)	**Total** (MMBOE)
Proved Reserves					
Developed Producing	920	27	65	1,352	1,238
Developed Non-Producing	214	2	3	38	224
Undeveloped	4,608	–	17	276	4,672
Proved Reserves	5,742	29	85	1,666	6,134
Probable Reserves	1,791	152	52	902	2,145
Proved plus Probable Reserves	7,533	181	137	2,568	8,279

(1) Before royalties excludes royalty interest reserves.
(2) Includes heavy crude oil that is not material.
(3) Includes shale gas that is not material.

China **Before Royalties**[1]	**Bitumen** (MMbbls)	**Light and Medium Oil** (MMbbls)	**NGLs** (MMbbls)	**Conventional Natural Gas** (Bcf)	**Total** (MMBOE)
Proved Reserves					
Developed Producing	–	–	18	493	100
Developed Non-Producing	–	–	–	–	–
Undeveloped	–	–	–	–	–
Proved Reserves	–	–	18	493	100
Probable Reserves	–	–	1	63	12
Proved plus Probable Reserves	–	–	19	556	112

(1) Before royalties excludes royalty interest reserves.

Indonesia Before Royalties(1)	Bitumen (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas (Bcf)	Total (MMBOE)
Proved Reserves					
Developed Producing	–	–	4	129	26
Developed Non-Producing	–	–	–	–	–
Undeveloped	–	–	–	68	11
Proved Reserves	–	–	4	197	37
Probable Reserves	–	–	2	56	11
Proved plus Probable Reserves	–	–	6	253	48

(1) Before royalties excludes royalty interest reserves.

Company Total Before Royalties(1)	Bitumen(2) (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas(3) (Bcf)	Total (MMBOE)
Proved Reserves					
Developed Producing	920	27	87	1,974	1,364
Developed Non-Producing	214	2	3	38	224
Undeveloped	4,608	–	17	344	4,683
Proved Reserves	5,742	29	107	2,356	6,271
Probable Reserves	1,791	152	55	1,021	2,168
Proved plus Probable Reserves	7,533	181	162	3,377	8,439

(1) Before royalties excludes royalty interest reserves.
(2) Includes heavy crude oil that is not material.
(3) Includes shale gas that is not material.

Summary of Net Present Value of Future Net Revenue as at December 31, 2020
(after giving effect to the Husky Arrangement)
(Forecast prices and costs)

Canada	Discounted at %/year ($ millions)				
Before Income Taxes	0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	8,309	12,620	11,915	10,783	9,756
Developed Non-Producing	4,023	3,041	2,362	1,880	1,528
Undeveloped	94,363	34,510	15,694	8,275	4,792
Proved Reserves	106,695	50,171	29,971	20,938	16,076
Probable Reserves	55,558	16,993	8,142	4,961	3,370
Proved plus Probable Reserves	162,253	67,164	38,113	25,899	19,446

China	Discounted at %/year ($ millions)				
Before Income Taxes	0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	5,049	4,225	3,635	3,196	2,860
Developed Non-Producing	–	–	–	–	–
Undeveloped	–	–	–	–	–
Proved Reserves	5,049	4,225	3,635	3,196	2,860
Probable Reserves	565	404	309	248	206
Proved plus Probable Reserves	5,614	4,629	3,944	3,444	3,066

Indonesia	Discounted at %/year ($ millions)				
Before Income Taxes	0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	435	372	324	287	257
Developed Non-Producing	–	–	–	–	–
Undeveloped	241	194	157	128	106
Proved Reserves	676	566	481	415	363
Probable Reserves	179	117	80	56	41
Proved plus Probable Reserves	855	683	561	471	404

Company Total	Discounted at %/year ($ millions)				
Before Income Taxes	0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	13,793	17,217	15,874	14,266	12,873
Developed Non-Producing	4,023	3,041	2,362	1,880	1,528
Undeveloped	94,604	34,704	15,851	8,403	4,898
Proved Reserves	112,420	54,962	34,087	24,549	19,299
Probable Reserves	56,302	17,514	8,531	5,265	3,617
Proved plus Probable Reserves	168,722	72,476	42,618	29,814	22,916

Total Future Net Revenue (undiscounted) as at December 31, 2020
(after giving effect to the Husky Arrangement)
(Forecast prices and costs - $ millions)

Canada Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Total Abandonment and Reclamation Costs(1)	Future Net Revenue Before Future Income Taxes
Proved Reserves	310,192	62,070	87,376	41,556	12,495	106,695
Proved plus Probable Reserves	449,680	94,168	118,047	61,402	13,810	162,253

(1) Total abandonment and reclamation costs included for all wells, facilities and other liabilities, known and existing, and to be incurred as a result of future development activity.

China Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Total Abandonment and Reclamation Costs(1)	Future Net Revenue Before Future Income Taxes
Proved Reserves	6,953	376	1,368	–	160	5,049
Proved plus Probable Reserves	7,727	419	1,534	–	160	5,614

(1) Total abandonment and reclamation costs included for all wells, facilities and other liabilities, known and existing, and to be incurred as a result of future development activity.

Indonesia Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Total Abandonment and Reclamation Costs(1)	Future Net Revenue Before Future Income Taxes
Proved Reserves	2,342	719	883	36	28	676
Proved plus Probable Reserves	3,052	1,048	1,081	36	32	855

(1) Total abandonment and reclamation costs included for all wells, facilities and other liabilities, known and existing, and to be incurred as a result of future development activity.

Company Total Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Total Abandonment and Reclamation Costs(1)	Future Net Revenue Before Future Income Taxes
Proved Reserves	319,487	63,165	89,627	41,592	12,683	112,420
Proved plus Probable Reserves	460,459	95,635	120,662	61,438	14,002	168,722

(1) Total abandonment and reclamation costs included for all wells, facilities and other liabilities, known and existing, and to be incurred as a result of future development activity.

Pricing Assumptions **(after giving effect to the Husky Arrangement)**

Except as noted below, the forecast of prices, inflation and exchange rate provided in the table below is computed using the IQRE Average Forecast and is used to estimate FNR associated with the reserves after giving effect to the Husky Arrangement. The IQRE Average Forecast is dated January 1, 2021. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs. China and Indonesia gas prices are derived from the gas sales agreements specific to each set of projects.

	Oil and Liquids				Natural Gas				
						Asia Pacific			
Year	WTI Cushing Oklahoma (US$/bbl)	Edmonton Par Price 40 API (C$/bbl)	Western Canadian Select (C$/bbl)	Edmonton C5+ (C$/bbl)	AECO Gas Price (C$/MMBtu)	China Gas Price(1) (US$/Mcf)	Indonesia Gas Price(1) (US$/Mcf)	Inflation Rate (%/year)	Exchange Rate (US$/C$)
2021	47.17	55.76	44.63	59.24	2.78	8.98	7.53	0.0	0.7683
2022	50.17	59.89	48.18	63.19	2.70	9.18	7.32	1.3	0.7650
2023	53.17	63.48	52.10	67.34	2.61	8.96	7.17	2.0	0.7633
2024	54.97	65.76	54.10	69.77	2.65	9.02	7.30	2.0	0.7633
2025	56.07	67.13	55.19	71.18	2.70	9.08	7.44	2.0	0.7633
2026	57.19	68.53	56.29	72.61	2.76	9.17	7.54	2.0	0.7633
2027	58.34	69.95	57.42	74.07	2.81	9.22	7.68	2.0	0.7633
2028	59.50	71.40	58.57	75.56	2.86	9.04	7.84	2.0	0.7633
2029	60.69	72.88	59.74	77.08	2.92	8.93	7.92	2.0	0.7633
2030	61.91	74.34	60.93	78.62	2.98	8.72	8.04	2.0	0.7633
2031	63.15	75.83	62.15	80.19	3.04	8.38	8.10	2.0	0.7633
2032+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr			2.0	0.7633

(1) China and Indonesia gas prices are derived from the gas sales agreements specific to each set of projects.

Future Development Costs **(after giving effect to the Husky Arrangement)**

The following tables outline undiscounted future development costs deducted in the estimation of FNR after giving effect to the Husky Arrangement for the years indicated:

Canada

Reserves Category ($ millions)	2021	2022	2023	2024	2025	Remainder	Total
Proved Reserves	612	807	1,321	1,186	1,090	36,540	41,556
Proved plus Probable Reserves	821	1,547	2,011	2,023	1,484	53,516	61,402

China

Reserves Category ($ millions)	2021	2022	2023	2024	2025	Remainder	Total
Proved Reserves	–	–	–	–	–	–	–
Proved plus Probable Reserves	–	–	–	–	–	–	–

Indonesia

Reserves Category ($ millions)	2021	2022	2023	2024	2025	Remainder	Total
Proved Reserves	13	23	–	–	–	–	36
Proved plus Probable Reserves	13	23	–	–	–	–	36

Company Total

Reserves Category ($ millions)	2021	2022	2023	2024	2025	Remainder	Total
Proved Reserves	625	830	1,321	1,186	1,090	36,540	41,592
Proved plus Probable Reserves	834	1,570	2,011	2,023	1,484	53,516	61,438

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

The following tables summarize Cenovus's interests in producing and non-producing wells, as at December 31, 2020:

	Oil		Gas		Total	
Producing Wells	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Sands(1)	731	731	232	214	963	945
Conventional(2)	608	361	3,954	2,856	4,562	3,217
Total	1,339	1,092	4,186	3,070	5,525	4,162

(1) All producing Oil Sands wells are located in Alberta.
(2) Includes 4,161 gross producing wells (2,889 net producing wells) located in Alberta; 401 gross producing wells (328 net producing wells) located in British Columbia.

	Oil		Gas		Total	
Non-Producing Wells(1)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil Sands(2)	220	220	213	197	433	417
Conventional(3)	348	196	875	578	1,223	774
Total	568	416	1,088	775	1,656	1,191

(1) Non-producing wells include wells which are capable of producing, but which are currently not producing. Non-producing wells do not include other types of wells such as stratigraphic test wells, service wells, or wells that have been abandoned.
(2) All non-producing Oil Sands wells are located in Alberta.
(3) Includes 1,152 gross non-producing wells (730 net non-producing wells) located in Alberta; 70 gross non-producing wells (43 net non-producing wells) located in British Columbia; one gross non-producing wells (one net non-producing wells) located in Saskatchewan.

As at December 31, 2020, Cenovus had no material properties with attributed reserves which are capable of producing, but which are not on production.

Exploration and Development Activity

The following tables summarize Cenovus's gross participation and net interest in wells drilled in 2020(1):

	Oil Sands		Conventional		Total	
Wells Drilled	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil	155	155	-	-	155	155
Gas	-	-	7	6	7	6
Dry & Abandoned	-	-	-	-	-	-
Total Canada	155	155	7	6	162	161

(1) Oil Sands drilled no gross exploration wells (no net wells) in 2020. No exploration wells were drilled in Conventional in 2020.

During the year ended December 31, 2020, Oil Sands drilled 155 gross stratigraphic test wells (155 net wells). Conventional drilled no stratigraphic test wells.

During the year ended December 31, 2020, no service wells were drilled within Oil Sands and no service wells were drilled in Conventional.

SAGD well pairs are counted as a single oil producing well in the table above. During the year ended December 31, 2020, no well pairs were drilled.

For all types of wells except stratigraphic test wells, the calculation of the number of wells is based on the number of surface locations. For stratigraphic test wells, the calculation is based on the number of bottomhole locations.

Development activities were focused on sustaining bitumen production at Foster Creek and Christina Lake, and the production and de-risking resource potential of the Conventional properties.

Properties With No Attributed Reserves

Cenovus has approximately 5.7 million gross acres (4.6 million net acres) of properties in Canada to which no reserves have been specifically attributed. For lands in which Cenovus holds multiple leases under the same surface area, both gross and net areas have been counted for each lease.

Cenovus has rights to explore, develop, and exploit approximately 472,944 net acres that could potentially expire by December 31, 2021, which relate entirely to Crown and freehold land.

Properties with no attributed reserves include Crown lands where bitumen contingent and prospective resources have been identified and Crown lands where exploration activities to date have not identified potential reserves in commercial quantities. The Corporation regularly reviews the economic viability of these unproved properties on the basis of product pricing, capital availability and level of related infrastructure development. From this process, some properties are selected for future development activity while others are retained as inactive, sold, swapped or relinquished back to the mineral rights owner.

Additional Information Concerning Abandonment and Reclamation Costs

The estimated total future abandonment and reclamation costs for existing wells, facilities, and infrastructure is based on management's estimate of costs to remediate, reclaim and abandon wells and facilities having regard to Cenovus's working interest and the estimated timing of the costs to be incurred in future periods. Cenovus has developed a process to calculate these estimates, which considers

applicable regulations, actual and anticipated costs, type and size of the well or facility and the geographic location.

Cenovus has estimated undiscounted and uninflated future abandonment and reclamation costs for its existing upstream assets of approximately $2,508 million (approximately $543 million, discounted at 10 percent) at December 31, 2020, of which the Corporation expects to pay $124 million in the next three financial years.

Cenovus believes that the Husky Arrangement will increase estimated undiscounted and uninflated future abandonment and reclamation costs for its existing Canadian onshore and offshore upstream assets by approximately $3,455 million (approximately $1,553 million discounted at 10 percent), of which the Corporation expects to pay between $400 million and $500 million in the next three financial years. In Asia Pacific, and in accordance with the provisions of the regulations of the People's Republic of China, Husky had deposited funds into separate accounts restricted to the funding of future abandonment and reclamation costs. As at December 31, 2020, Husky has deposited funds of $164 million for future abandonment and reclamation costs, which were classified as non-current liabilities.

Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Cenovus's proved reserves, approximately $6.5 billion ($12.7 billion after giving effect to the Husky Arrangement) has been deducted in estimating the FNR, which represents the Corporation's total existing estimated abandonment and reclamation costs, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the reserves.

Tax Horizon

In 2020, the Corporation was subject to relatively insignificant cash taxes. Based on projected future net earnings (after taking into account the Husky Arrangement), the Corporation expects to pay cash taxes of approximately $200 million in 2021. This estimate could vary significantly if underlying assumptions change with respect to commodity prices, capital spending levels and acquisition and disposition transactions.

Costs Incurred

($ millions)	2020
Acquisitions	
Unproved	12
Proved	6
Total Acquisitions	**18**
Exploration Costs	**46**
Development Costs	**459**
Total Costs Incurred	**523**

Forward Contracts

Cenovus may use financial derivatives to manage its exposure to fluctuations in commodity prices, foreign exchange and interest rates. A description of such instruments is provided in the notes to the Corporation's annual audited Consolidated Financial Statements for the year ended December 31, 2020.

Production Estimates

The following table summarizes the 2021 estimated production of Company Interest Before Royalties reserves for all properties held on December 31, 2020 using forecast prices and costs, all of which will be produced in Canada. These estimates assume certain activities take place, such as the development of undeveloped reserves, and that there are no divestitures.

2021 Estimated Production Forecast Prices and Costs	Proved	Proved plus Probable
Bitumen (bbls/d)(1)	392,037	402,414
Light and Medium Oil (bbls/d)	3,428	3,923
NGLs (bbls/d)	17,972	19,939
Conventional Natural Gas (MMcf/d)(2)	361	407
Total (BOE/d)	473,687	494,173

(1) Includes Foster Creek production of 157,823 barrels per day for proved and 159,550 barrels per day for proved plus probable, and Christina Lake production of 234,214 barrels per day for proved and 242,864 barrels per day for proved plus probable.
(2) Includes shale gas that is not material.

The following table summarizes the 2021 estimated production of Company Interest Before Royalties reserves for all properties held on December 31, 2020 after giving effect to the Husky Arrangement as though such transaction had occurred on December 31, 2020.

Canada

2021 Estimated Production Forecast Prices and Costs	Proved	Proved plus Probable
Bitumen (bbls/d)(1)	526,904	556,717
Light and Medium Oil (bbls/d)	20,066	22,387
NGLs (bbls/d)	26,707	29,240
Conventional Natural Gas (MMcf/d)(2)	580	637
Total (BOE/d)	670,358	714,479

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.

China

2021 Estimated Production Forecast Prices and Costs	Proved	Proved plus Probable
Bitumen (bbls/d)	-	-
Light and Medium Oil (bbls/d)	-	-
NGLs (bbls/d)	9,191	9,405
Conventional Natural Gas (MMcf/d)	235	239
Total (BOE/d)	48,307	49,282

Indonesia

2021 Estimated Production Forecast Prices and Costs	Proved	Proved plus Probable
Bitumen (bbls/d)	-	-
Light and Medium Oil (bbls/d)	-	-
NGLs (bbls/d)	2,493	2,514
Conventional Natural Gas (MMcf/d)	38	38
Total (BOE/d)	8,886	8,907

Company Total

2021 Estimated Production Forecast Prices and Costs	Proved	Proved plus Probable
Bitumen (bbls/d)(1)	526,904	556,717
Light and Medium Oil (bbls/d)	20,066	22,387
NGLs (bbls/d)	38,391	41,159
Conventional Natural Gas (MMcf/d)(2)	853	914
Total (BOE/d)	727,551	772,668

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.

Production History and Per-Unit Results

	2020	Q4	Q3	Q2	Q1
Bitumen					
Total Production (bbls/d)	381,723	380,693	385,937	373,189	387,036
Foster Creek	163,210	158,068	164,954	166,032	163,820
Christina Lake	218,513	222,625	220,983	207,157	223,216
Sales Price ($/bbl)	28.64	39.02	39.67	12.64	22.35
Royalties ($/bbl)	2.34	3.73	3.54	0.80	1.21
Transportation and blending ($/bbl)	8.70	7.90	7.51	8.56	10.81
Operating expenses ($/bbl)	7.84	8.70	7.53	7.36	7.75
Netback excluding realized risk management (1)	9.76	18.69	21.09	(4.08)	2.58
Heavy Oil					
Total Production (bbls/d)	2,751	1,966	3,236	2,232	3,576
Sales Price ($/bbl)	31.45	38.85	39.54	15.76	29.09
Royalties ($/bbl)	1.52	2.20	2.61	0.02	1.04
Transportation and blending ($/bbl)	2.02	2.42	2.45	1.18	1.89
Operating expenses ($/bbl)	9.78	8.72	6.91	13.68	10.70
Netback excluding realized risk management (1)	18.13	25.51	27.57	0.88	15.46
Light and Medium Oil					
Total Production (bbls/d)	4,493	4,263	4,318	4,309	5,086
Sales Price ($/bbl)	42.78	44.80	49.19	27.47	48.54
Royalties ($/bbl)	5.87	4.77	6.06	4.71	7.63
Transportation and blending ($/bbl)	3.20	2.74	4.21	3.13	2.78
Operating expenses ($/bbl)	10.81	10.30	10.85	10.25	11.67
Netback excluding realized risk management (1)	22.90	26.99	28.07	9.38	26.46
Natural Gas (2)					
Total Production (MMcf/d)	380	371	360	392	395
Sales Price ($/Mcf)	2.37	2.94	2.34	2.04	2.17
Royalties ($/Mcf)	0.10	0.06	0.28	0.04	0.02
Transportation and blending ($/Mcf)	0.32	0.30	0.32	0.32	0.33
Operating expenses ($/Mcf)	1.47	1.35	1.58	1.46	1.48
Netback excluding realized risk management (1)	0.48	1.23	0.16	0.22	0.34
NGLs					
Total Production (bbls/d)	19,513	18,358	18,297	20,320	21,104
Sales Price ($/bbl)	22.04	27.76	21.38	18.74	20.75
Royalties ($/bbl)	2.19	5.27	6.45	(1.38)	(0.80)
Transportation and blending ($/bbl)	4.15	3.75	4.66	3.87	4.34
Operating expenses ($/bbl)	9.06	8.61	9.98	9.33	8.40
Netback excluding realized risk management (1)	6.64	10.13	0.29	6.92	8.81

(1) Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netback is defined as gross sales less royalties, transportation and blending and operating expenses divided by sales volumes. Netbacks do not reflect non-cash write-downs (reversals) of product inventory until the inventory is sold. This calculation is consistent with the definition found in the Canadian Oil and Gas Evaluation Handbook. The crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Netback does not have a standardized meaning as prescribed by IFRS and therefore is considered a non-GAAP measure. As such, it may not be comparable to similar measures presented by other issuers. This measure has been described and presented in this AIF in order to provide shareholders and potential investors with additional information regarding Cenovus's liquidity and its ability to generate funds to finance its operations, and to comply with the requirements of NI 51-101. This measure should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. For further information, refer to Cenovus's most recent MD&A available at cenovus.com. For the reconciliation of the financial components of Netback to the GAAP measure and the sales volumes used in the calculations, see "Netback Reconciliations" in Appendix D.

(2) Includes shale gas that is not material.

DIVIDENDS

The declaration of dividends is at the sole discretion of Cenovus's Board and is considered each quarter. On April 2, 2020 the Board announced the temporary suspension of the dividend in response to the low global crude oil price environment resulting in no dividends paid in the second, third and fourth quarters of 2020. The Board has approved a first quarter dividend of $0.0175 per share payable on March 31, 2021 to holders of Common Shares of record as of March 15, 2021. The Board declared a first quarter dividend on the Series 1, 2, 3, 5, and 7 First Preferred Shares, payable on March 31, 2021, in the amount of $8.5 million. Readers should also refer to the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2020 MD&A, which section of the MD&A is incorporated by reference into this AIF, for additional information.

Cenovus paid the following Common Share dividends over the last three years:

Common Share Dividends Paid

($ per share)	Year	Q4	Q3	Q2	Q1
2020	0.0625	-	-	-	0.0625
2019	0.2125	0.0625	0.05	0.05	0.05
2018	0.20	0.05	0.05	0.05	0.05

Cenovus is authorized to issue an unlimited number of Common Shares, and First Preferred Shares and Second Preferred Shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding Common Shares. In connection with the Husky Arrangement, Cenovus's articles were amended effective December 30, 2020 to create the Series 1 First Preferred Shares, the Series 2 First Preferred Shares, the Series 3 First Preferred Shares, the Series 4 First Preferred Shares, the Series 5 First Preferred Shares, the Series 6 First Preferred Shares, the Series 7 First Preferred Shares and the Series 8 First Preferred Shares.

As at December 31, 2020, there were approximately 1,228.9 million Common Shares and no First or Second Preferred Shares outstanding.

As at January 1, 2021, following completion of the Husky Arrangement, there were approximately 2,017.4 million Common Shares, 65.4 million Cenovus Warrants and 36.0 million First Preferred Shares outstanding (consisting of approximately 10.4 million Series 1 First Preferred Shares, 1.6 million Series 2 First Preferred Shares, 10.0 million Series 3 First Preferred Shares, 8.0 million Series 5 First Preferred Shares and 6.0 million Series 7 First Preferred Shares).

COMMON SHARES

The holders of Common Shares are entitled to: (i) receive dividends if, as and when declared by Cenovus's Board; (ii) receive notice of, to attend, and to vote on the basis of one vote per Common Share held, at all meetings of shareholders; and (iii) participate in any distribution of the Corporation's assets in the event of liquidation, dissolution or winding up or other distribution of its assets among its shareholders for the purpose of winding up its affairs.

PREFERRED SHARES

Cenovus may issue preferred shares in one or more series. Cenovus's Board may determine the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares before the issue of such series. Holders of Preferred Shares are not entitled to vote at any meeting of shareholders but may be entitled to vote if the Corporation fails to pay dividends on that series of Preferred Shares. The First Preferred Shares are entitled to priority over the Second Preferred Shares and the Common Shares with respect to the payment of dividends and the distribution of assets in the event of any liquidation, dissolution or winding up of Cenovus's affairs. The aggregate number of Preferred Shares issued by the Corporation may not exceed 20 percent of the aggregate number of the then-outstanding Common Shares.

Series 1 First Preferred Shares

Holders of Series 1 First Preferred Shares are entitled to receive a cumulative quarterly fixed rate dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board.

For the five-year period commencing March 31, 2016 to, but excluding, March 31, 2021, the dividend rate applicable to the Series 1 First Preferred Shares is set at 2.404%. Every fifth year thereafter, the dividend rate will be reset at the rate equal to the sum of the five-year Government of Canada bond yield on the applicable calculation date plus 1.73%.

Holders of Series 1 First Preferred Shares will have the right, at their option, to convert their Series 1 First Preferred Shares into Series 2 First Preferred Shares, subject to certain conditions, on March 31, 2021, and on March 31 every five years thereafter.

Cenovus may, at its option, redeem all or any number of the then-outstanding Series 1 First Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter, by payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

Series 2 First Preferred Shares

Holders of Series 2 First Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board.

The dividend rate is reset each quarter at the rate equal to the sum of the 90-day Government of Canada Treasury Bill yield on the applicable calculation date plus 1.73%.

Holders of Series 2 First Preferred Shares will have the right, at their option, to convert their Series 2 First Preferred Shares into Series 1 First Preferred Shares, subject to certain conditions, on March 31, 2021, and on March 31 every five years thereafter.

Cenovus may, at its option, redeem all or any number of the then-outstanding Series 2 First Preferred Shares, subject to certain conditions, on (i) March 31, 2021 and on March 31 every five years thereafter, by payment of an amount in cash for each share to be redeemed equal to $25.00 and (ii) any other date that is not a Series 2 First Preferred Share conversion date, by payment of an amount in cash for each share to be redeemed equal to $25.50, plus in each case all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

Series 3 First Preferred Shares

Holders of Series 3 First Preferred Shares are entitled to receive a cumulative quarterly fixed rate dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board.

For the five-year period commencing December 31, 2019 to, but excluding, December 31, 2024, the dividend rate applicable to the Series 3 First Preferred Shares is set at 4.689%. Every fifth year thereafter, the dividend rate will be reset at the rate equal to the sum of the five-year Government of Canada bond yield on the applicable calculation date plus 3.13%.

Holders of Series 3 First Preferred Shares will have the right, at their option, to convert their Series 3 First Preferred Shares into Series 4 First Preferred Shares, subject to certain conditions, on December 31, 2024, and on December 31 every five years thereafter.

Cenovus may, at its option, redeem all or any number of the then-outstanding Series 3 First Preferred Shares, subject to certain conditions, on December 31, 2024 and on December 31 every five years thereafter, by payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

Series 4 First Preferred Shares

Holders of Series 4 First Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board.

The dividend rate is reset each quarter at the rate equal to the sum of the 90-day Government of Canada Treasury Bill yield on the applicable calculation date plus 3.13%.

Holders of Series 4 First Preferred Shares will have the right, at their option, to convert their Series 4 First Preferred Shares into Series 3 First Preferred Shares, subject to certain conditions, on December 31, 2024 and on December 31 every five years thereafter.

Cenovus may, at its option, redeem all or any number of the then-outstanding Series 4 First Preferred Shares, subject to certain conditions, on (i) December 31, 2024 and on December 31 every five years thereafter, by payment of an amount in cash for each share to be redeemed equal to $25.00 and (ii) any other date that is not a Series 4 First Preferred Share conversion date, by payment of an amount in cash for each share to be redeemed equal to $25.50, plus in each case all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

Series 5 First Preferred Shares

Holders of Series 5 First Preferred Shares are entitled to receive a cumulative quarterly fixed rate dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board.

For the five-year period commencing March 31, 2020 to, but excluding, March 31, 2025, the dividend rate applicable to the Series 5 First Preferred Shares is set at 4.591%. Every fifth year thereafter, the dividend rate will be reset at the rate equal to the sum of the five-year Government of Canada bond yield on the applicable calculation date plus 3.57%.

Holders of Series 5 First Preferred Shares will have the right, at their option, to convert their Series 5 First Preferred Shares into Series 6 First Preferred Shares, subject to certain conditions, on March 31, 2025 and on March 31 every five years thereafter.

Cenovus may, at its option, redeem all or any number of the then-outstanding Series 5 First Preferred Shares, subject to certain conditions, on March 31, 2025 and on March 31 every five years thereafter, by payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

Series 6 First Preferred Shares

Holders of Series 6 First Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board.

The dividend rate is reset each quarter at the rate equal to the sum of the 90-day Government of Canada Treasury Bill yield on the applicable calculation date plus 3.57%.

Holders of Series 6 First Preferred Shares will have the right, at their option, to convert their Series 6 First Preferred Shares into Series 5 First Preferred Shares, subject to certain conditions, on March 31, 2025 and on March 31 every five years thereafter.

Cenovus may, at its option, redeem all or any number of the then-outstanding Series 6 First Preferred Shares, subject to certain conditions, on (i) March 31, 2025 and on March 31 every five years thereafter, by payment of an amount in cash for each share to be redeemed equal to $25.00 and (ii) any other date that is not a Series 6 First Preferred Share conversion date, by payment of an amount in cash for each share to be redeemed equal to $25.50, plus in each case all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

Series 7 First Preferred Shares

Holders of Series 7 First Preferred Shares are entitled to receive a cumulative quarterly fixed rate dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board.

For the five-year period commencing June 30, 2020 to, but excluding, June 30, 2025, the dividend rate applicable to the Series 5 First Preferred Shares is set at 3.935%. Every fifth year thereafter, the dividend rate will be reset at the rate equal to the sum of the five-year Government of Canada bond yield on the applicable calculation date plus 3.52%.

Holders of Series 7 First Preferred Shares will have the right, at their option, to convert their Series 7 First Preferred Shares into Series 8 First Preferred

Shares, subject to certain conditions, on June 30, 2025 and on June 30 every five years thereafter.

Cenovus may, at its option, redeem all or any number of the then-outstanding Series 7 First Preferred Shares, subject to certain conditions, on June 30, 2025 and on June 30 every five years thereafter, by payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

Series 8 First Preferred Shares

Holders of Series 8 First Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board.

The dividend rate is reset each quarter at the rate equal to the sum of the 90-day Government of Canada Treasury Bill yield on the applicable calculation date plus 3.52%.

Holders of Series 8 First Preferred Shares will have the right, at their option, to convert their Series 8 First Preferred Shares into Series 7 First Preferred Shares, subject to certain conditions, on June 30, 2025 and on June 30 every five years thereafter.

Cenovus may, at its option, redeem all or any number of the then-outstanding Series 8 First Preferred Shares, subject to certain conditions, on (i) June 30, 2025 and on June 30 every five years thereafter, by payment of an amount in cash for each share to be redeemed equal to $25.00 and (ii) any other date that is not a Series 8 First Preferred Share conversion date, by payment of an amount in cash for each share to be redeemed equal to $25.50, plus in each case all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

Cenovus Warrants

The Cenovus Warrants were created and issued pursuant to the terms of the warrant indenture dated January 1, 2021 (the "Warrant Indenture") between Cenovus and Computershare Trust Company of Canada, as warrant agent.

Each whole Cenovus Warrant is exercisable for one Common Share at any time up to 4:30 pm (MST) on January 1, 2026, with an exercise price of $6.54 per Common Share, subject to adjustment in accordance with the terms of the Warrant Indenture. Cenovus Warrants do not have voting or any other rights of Common Shares. A copy of the Warrant Indenture is filed and available on SEDAR under Cenovus's profile at sedar.com and on EDGAR at sec.gov.

SHAREHOLDER RIGHTS PLAN

Cenovus has a shareholder rights plan (the "Shareholder Rights Plan") which was adopted in 2009 and creates a right that attaches to each issued Common Share. Until the separation time, which typically occurs at the time of an unsolicited take-over bid, whereby a person acquires or attempts to acquire 20 percent or more of Cenovus's Common Shares, the rights are not separable from the Common Shares, are not exercisable and no separate rights certificates are issued. Each right entitles the holder, other than the 20 percent acquiror, from and after the separation time (unless delayed by Cenovus's Board) and before certain expiration times, to acquire Common Shares at 50 percent of the market price at the time of exercise. In connection with the Husky Arrangement, the Corporation's shareholders approved certain amendments to the Shareholder Rights Plan to ensure that an acquisition by any person of Common Shares or of rights to acquire Common Shares pursuant to (i) the Husky Arrangement, (ii) the Cenovus Warrants, including the exercise thereof, or (iii) any exercise of pre-emptive rights, including pursuant to any follow-on offering, under any Husky Arrangement Pre-Emptive Rights Agreement (defined below) does not and will not result in the occurrence of a "Flip-In Event" or the "Separation Time" (as those terms are defined in the Shareholder Rights Plan). The Shareholder Rights Plan was reconfirmed at the 2018 annual meeting of shareholders and must be reconfirmed by the Corporation's shareholders every three years. Shareholders will be asked to approve certain amendments and reconfirm the plan at the 2021 annual meeting of shareholders.

DIVIDEND REINVESTMENT PLAN

Cenovus has a dividend reinvestment plan which permits holders of Common Shares to automatically reinvest all or any portion of the cash dividends paid on their Common Shares in additional Common Shares. At the discretion of the Corporation, the additional Common Shares may be issued from treasury at the volume weighted average price of the Common Shares (denominated in the currency in which the Common Shares trade on the applicable stock exchange) traded on the Toronto Stock Exchange ("TSX") during the last five trading days preceding the relevant dividend payment date or purchased on the market.

RATINGS

The following information relating to Cenovus's credit ratings is provided as it relates to the Corporation's financing costs and liquidity. Specifically, credit ratings affect Cenovus's ability to obtain short-term and long-term financing and the cost of such financing. A reduction in the current rating on Cenovus's debt by the Corporation's rating agencies or a negative change in its ratings outlook could adversely affect Cenovus's cost of financing, its access to sources of liquidity and capital, and potentially obligate it to post incremental collateral in the form of cash, letters of credit or other financial instruments. See the section entitled "Risk Management and Risk Factors" in the Corporation's annual 2020 MD&A, which section of the MD&A is incorporated by reference into this AIF, for further information.

The following table outlines the current ratings and outlooks of Cenovus's debt and First Preferred Shares:

	S&P Global Ratings ("S&P")	Moody's Investors Service ("Moody's")	DBRS Limited ("DBRS")	Fitch Ratings Inc. ("Fitch")
Senior Unsecured				
Long-Term Rating	BBB-	Baa3	BBB	BB+
Outlook/Trend	Stable	Negative	Stable	Positive
Series 1 First Preferred Shares	P-3		Pfd-3	
Series 2 First Preferred Shares	P-3		Pfd-3	
Series 3 First Preferred Shares	P-3		Pfd-3	
Series 5 First Preferred Shares	P-3		Pfd-3	
Series 7 First Preferred Shares	P-3		Pfd-3	

Credit ratings are intended to provide an independent measure of the credit quality of an issue of securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities nor do the ratings comment on market price or suitability for a particular investor. A rating may not remain in effect for any given period of time and may be revised or withdrawn entirely by a rating agency at any time in the future if, in its judgment, circumstances so warrant.

S&P's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB- by S&P is within the fourth highest of 10 categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a "+" or "-" designation after a rating indicates the relative standing within the major rating categories. An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate term (generally up to two years for investment grade and generally up to one year for speculative grade). Rating outlooks fall into four categories – "Positive", "Negative", "Stable" and "Developing". In determining a rating outlook, consideration is given to any changes in the economic and/or fundamental business conditions. A "Stable" outlook indicates that a rating is not likely to change.

S&P began rating Cenovus's First Preferred Shares on its Canadian preferred share scale in conjunction with the Husky Arrangement. S&P's preferred share ratings are a forward-looking opinion about the creditworthiness of an issuer with respect to a specific preferred share obligation. There is a direct correspondence between the ratings assigned on the preferred share scale and S&P's ratings scale for long-term credit ratings. According to S&P's ratings system, a P-3 rating on the Canadian preferred share rating scale is equivalent to a BB rating on the long-term credit rating scale. A rating of BB by S&P is within the fifth highest of 10 categories and indicates that the obligation is less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitments on the issue.

Moody's long-term credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. A rating of Baa3 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are considered to be medium grade and subject to moderate credit risk and as such may possess certain speculative characteristics. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 3 indicates that the issue ranks in the lower end of its generic rating category. A Moody's rating outlook is an opinion regarding the likely rating direction over the medium term. Rating outlooks fall into four categories – "Positive", "Negative", "Stable", and "Developing". A designation of Negative indicates a higher likelihood of a downward rating change over the medium term.

DBRS's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BBB by DBRS is within the fourth highest of 10 categories and is assigned to debt securities considered to be of adequate credit quality, with acceptable capacity for payment of financial obligations. Entities in the BBB category may be vulnerable to future events. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. The absence of either modifier indicates the rating is in the middle of the category. Rating trends provide guidance in respect of DBRS's opinion regarding the outlook for the rating in question, with rating trends falling into one of three categories - "Positive", "Stable" or "Negative". The rating trend

indicates the direction in which DBRS considers the rating is headed should present circumstances continue, or in some cases, unless challenges are addressed.

DBRS began rating Cenovus's First Preferred Shares on its Preferred Share Rating Scale in conjunction with the Husky Arrangement. DBRS's preferred share ratings are meant to give an indication of the risk that an issuer will not fulfill its full obligations in a timely manner, with respect to both dividend and principal commitments. DBRS's preferred share ratings range from Pdf 1 (highest) to D (lowest). According to DBRS's ratings system, preferred shares rated Pfd-3 are generally of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection.

Fitch's long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. A rating of BB+ is within the fifth highest of 11 categories and is assigned to debt securities that indicate an elevated vulnerability to default risk, particularly in the event of adverse changes in business or economic conditions over time; however, business or financial flexibility exists that supports the servicing of financial commitments. The modifiers "+" or "-" may be appended to a rating to denote relative status within major rating categories. A Fitch rating outlook indicates the direction a rating is likely to move over a one to two-year period, with rating outlooks falling into four categories: "Positive", "Negative", "Stable" or "Evolving". Rating outlooks reflect financial or other trends that have not yet reached, or have not been sustained at, a level that would trigger a rating action, but which may do so if such trends continue. Positive or Negative outlooks do not imply that a rating change is inevitable and similarly, ratings with Stable outlooks can be raised or lowered without prior revision of the outlook. Where the fundamental trend has strong, conflicting elements of both positive and negative, the rating outlook may be described as Evolving. A Positive Rating Outlook indicates an upward trend on the rating scale.

Throughout the last four years, Cenovus has made payments to each of S&P, Moody's, DBRS and Fitch related to the rating of the Corporation's debt. Additionally, Cenovus has purchased products and services from S&P, Moody's, DBRS and Fitch.

MARKET FOR SECURITIES

All of the outstanding Common Shares are listed and posted for trading on the TSX and the New York Stock Exchange ("NYSE") under the symbol CVE. The following table outlines the share price trading range and volume of shares traded by month in 2020:

	TSX				NYSE			
	Share Price Trading Range				Share Price Trading Range			
	High(1)	Low(1)	Close(1)	Share Volume(2)	High(3)	Low(3)	Close(3)	Share Volume(4)
	($ per share)			(thousands)	(US$ per share)			(thousands)
January	13.66	11.16	11.52	182,247	10.49	8.48	8.71	79,957
February	12.45	9.41	9.87	195,111	9.39	7.00	7.37	93,778
March	10.07	2.06	2.84	708,848	7.56	1.41	2.02	279,556
April	5.23	2.52	5.05	613,431	3.76	1.78	3.64	258,256
May	6.23	4.49	6.00	316,128	4.52	3.18	4.33	154,383
June	7.80	5.78	6.35	314,857	5.83	4.22	4.67	174,588
July	6.83	5.64	5.96	222,733	5.09	4.14	4.46	123,288
August	7.10	6.01	6.16	143,362	5.34	4.44	4.72	83,900
September	6.39	5.01	5.19	171,061	4.87	3.74	3.89	110,017
October	5.52	4.15	4.36	339,354	4.21	3.15	3.28	194,243
November	7.27	4.32	6.44	287,148	5.57	3.26	4.96	159,416
December	8.21	6.40	7.75	268,814	6.44	4.94	6.04	170,007

(1) As reported by the TSX.
(2) As reported by all Canadian marketplaces. Source: Bloomberg.
(3) As reported by the NYSE.
(4) As reported by all U.S. marketplaces. Source: Bloomberg.

As of January 6, 2021, the Cenovus Warrants are listed and posted for trading on the TSX under the symbol CVE.WT and on the NYSE under the symbol CVE WS and the Series 1 First Preferred Shares, Series 2 First Preferred Shares, Series 3 First Preferred Shares, Series 5 First Preferred Shares and Series 7 First Preferred Shares are listed and posted for trading on the TSX under the symbols CVE.PR.A, CVE.PR.B, CVE.PR.C, CVE.PR.E and CVE.PR.G, respectively.

DIRECTORS

The following individuals are the directors of Cenovus:

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Keith M. Casey[3,5] San Antonio, Texas, United States	2020 Independent	Mr. Casey is the Chief Executive Officer of Tatanka Midstream LLC, a private midstream company, since March 2020. Mr. Casey spent five years with Andeavor Corporation ("Andeavor"), formerly known as Tesoro Corporation, an integrated petroleum refining, logistics, and marketing company and served as Executive Vice-President Commercial and Value Chain of Andeavor, from August 2016 to October 2018, Executive Vice-President, Operations of Andeavor from May 2014 to August 2016, and Senior Vice-President, Strategy and Business Development of Andeavor from April 2013 to May 2014. Mr. Casey served as a director of Andeavor Logistics LP, formerly Tesoro Logistics LP, a publicly traded midstream service company, from April 2014 to April 2015 and has served as a director of a number of private midstream companies. Mr. Casey has worked in the refining industry since 1998 and prior to that, he held leadership and operational roles with BP Products North America Inc., Praxair Incorporated and Union Carbide Corp.
Canning K.N. Fok Hong Kong Special Administrative Region	2021 Non-independent	Mr. Fok is Chairman and a Director of Hutchison Telecommunications Hong Kong Holdings Limited, Hutchison Telecommunications (Australia) Limited, Hutchison Port Holdings Management Pte. Limited as the trustee-manager of Hutchison Port Holdings Trust, Power Assets Holdings Limited, HK Electric Investments Manager Limited as the trustee-manager of HK Electric Investments, and HK Electric Investments Limited. Mr. Fok is Deputy Chairman and an Executive Director of CK Infrastructure Holdings Limited, and a Non-Executive Director of TPG Telecom Limited. Mr. Fok is a director of Husky since 2000 and was Co-Chairman of Husky from 2000 to January 1, 2021.
Jane E. Kinney[2,5] Toronto, Ontario, Canada	2019 Independent	Ms. Kinney is a director of Intact Financial Corporation, a publicly traded insurance company, since May 2019. Ms. Kinney spent 25 years with Deloitte LLP Canada ("Deloitte") and was admitted to the Deloitte Partnership in 1997. She was appointed Vice Chair, Leadership Team Member of Deloitte in June 2010 and served in this role until her retirement in June 2019. Previous positions with Deloitte include Canadian Managing Partner, Quality & Risk from May 2010 to June 2015, Global Chief Risk Officer from June 2010 to May 2012, and Risk and Regulatory Practice Leader from June 1999 to May 2010. She has also served as a lecturer at the University of Manitoba, Dalhousie University and Saint Mary's University.
Harold N. Kvisle[3,4] Calgary, Alberta, Canada	2018 Independent	Mr. Kvisle is a director, since May 2009, and Chairman of ARC Resources Ltd., a publicly traded oil and gas company; and a director, since June 2017, and Board Chair of Finning International Inc., a publicly traded heavy equipment company. He served as a director of Cona Resources Ltd. ("Cona"), a publicly traded heavy oil company, from November 2011 to May 2018 when Cona was acquired by Waterous Energy Fund. Mr. Kvisle served as President and Chief Executive Officer of Talisman Energy Inc. ("Talisman"), a publicly traded oil and gas company, from September 2012 to May 2015 and as a director of Talisman from May 2010 to May 2015. From 2001 to 2010, Mr. Kvisle was President and Chief Executive Officer of TransCanada Corporation, now TC Energy Corporation ("TC Energy"), a publicly traded energy infrastructure company. Prior to joining TC Energy in 1999, he was the President of Fletcher Challenge Energy Canada Inc. Mr. Kvisle has worked in the oil and gas industry since 1975 and in the utilities and power industries since 1999.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Eva L. Kwok[3,4] Vancouver, British Columbia, Canada	2021 Independent	Mrs. Kwok is Chairman, a Director and Chief Executive Officer of Amara Holdings Inc., a private investment holding company. Mrs. Kwok is also a Director of CK Life Sciences Int'l., (Holdings) Inc., CK Infrastructure Holdings Limited and the Li Ka Shing (Canada) Foundation and a director of Husky since 2000.
Keith A. MacPhail[4,6] Calgary, Alberta, Canada	2018 Independent	Mr. MacPhail has served as the Chair of Cenovus's Board since April 2020. He is a director (since July 2003) and served as Chairman of NuVista Energy Ltd., a publicly traded oil and gas company, from July 2003 to May 2020. He also served as a director of Bonavista Energy Corporation, formerly Bonavista Petroleum Ltd. ("Bonavista"), a publicly traded oil and gas company, from November 1997 to August 2020; Chairman from March 2012 to August 2020; Executive Chairman from 2012 to 2018; Chairman and Chief Executive Officer from 2008 to 2012; and as President and Chief Executive Officer from 1997 to 2008. Mr. MacPhail served as a director of Canadian Natural Resources Limited ("CNRL") from 1993 to 2015. Prior to joining Bonavista in 1997, Mr. MacPhail held progressively more responsible positions with CNRL, with his final position being Executive Vice President and Chief Operating Officer. Previously, he held the position of Production Manager with Poco Petroleums Ltd.
Richard J. Marcogliese[2,5] Alamo, California, United States	2016 Independent	Mr. Marcogliese is the Principal of iRefine, LLC, a privately owned petroleum refining consulting company, since June 2011; and a director of Delek US Holdings, Inc., a publicly traded downstream energy company, since January 2020. He served as Executive Advisor of Pilko & Associates L.P., a private chemical and energy advisory company, from June 2011 to December 2019; Operations Advisor to NTR Partners III LLC, a private investment company from October 2013 to December 2017; and from September 2012 to January 2016 as Operations Advisor to the Chief Executive Officer of Philadelphia Energy Solutions, a partnership between The Carlyle Group and a subsidiary of Energy Transfer Partners, L.P. that operates an oil refining complex on the U.S. Eastern seaboard.
Claude Mongeau[2,5] Montreal, Quebec, Canada	2016 Independent	Mr. Mongeau is a director of The Toronto-Dominion Bank, an international financial institution, since March 2015; and a director of Norfolk Southern Corporation, a publicly traded North American rail transportation provider, since September 2019. He served as a director of TELUS Corporation, a publicly traded telecommunications company, from May 2017 to August 2019. He also served as a director of Canadian National Railway Company, a publicly traded railroad and transportation company, from October 2009 to July 2016 and as President and Chief Executive Officer from January 2010 to June 2016. During his tenure with Canadian National Railway Company, he also served as Executive Vice-President and Chief Financial Officer from October 2000 until December 2009 and held various increasingly senior positions from the time he joined in 1994. Mr. Mongeau also served as a director of SNC-Lavalin Group Inc. from August 2003 to May 2015.
Alexander J. Pourbaix[7] Calgary, Alberta, Canada	2017 Non-independent	Mr. Pourbaix has served as President & Chief Executive Officer of Cenovus since November 6, 2017 and is a director of Canadian Utilities Limited, a publicly traded diversified global energy infrastructure corporation, since November 2019. He served as a director of Trican Well Service Ltd., a publicly traded oilfield services provider, from May 2012 to December 2019. Mr. Pourbaix served as Chief Operating Officer of TC Energy from October 2015 to April 2017. During his tenure with TC Energy, he also served as Executive Vice-President and President, Development from March 2014 to September 2015 and President, Energy & Oil Pipelines from July 2010 to February 2014, and held various increasingly senior positions from the time he joined TC Energy in 1994.

Name and Residence	Director Since[1]	Principal Occupation During the Past Five Years
Wayne E. Shaw[2,5] Toronto, Ontario, Canada	2021 Independent	Mr. Shaw is the President of G.E. Shaw Investments Limited, a private investment holding company. Prior to his retirement in April 2013, he was a Senior Partner with Stikeman Elliott LLP, Barristers and Solicitors, Toronto, Ontario. Mr. Shaw is also a director of the Li Ka Shing (Canada) Foundation and a director of Husky since 2000.
Frank J. Sixt[4] Hong Kong Special Administrative Region	2021 Non-independent	Mr. Sixt is an Executive Director, Group Finance Director and Deputy Managing Director of CK Hutchison Holdings Limited. Mr. Sixt is also the Non-Executive Chairman of TOM Group Limited, an Executive Director of CK Infrastructure Holdings Limited, a Non-Executive Director of TPG Telecom Limited, a Director of Hutchison Telecommunications (Australia) Limited (HTAL) and an Alternate Director to a Director of HTAL, HK Electric Investments Manager Limited as the trustee-manager of HK Electric Investments and HK Electric Investments Limited. Mr. Sixt is also a Director of the Li Ka Shing (Canada) Foundation and a director of Husky since 2000.
Rhonda I. Zygocki[3,4] Friday Harbor, Washington, United States	2016 Independent	Ms. Zygocki served as Executive Vice President, Policy and Planning of Chevron Corporation ("Chevron"), a publicly traded integrated energy company, from March 2011 until her retirement in February 2015 and prior thereto, during her 34 years with Chevron, she held a number of senior management and executive leadership positions in international operations, public affairs, strategic planning, policy, government affairs and health, environment and safety.

(1) Directors were elected or appointed to Cenovus's Board as follows:
- *Ms. Zygocki and Mr. Marcogliese were first elected as directors of Cenovus's Board at the annual meeting of shareholders held on April 27, 2016;*
- *Mr. Mongeau was appointed as a director of Cenovus's Board as of December 1, 2016;*
- *Mr. Pourbaix was appointed as President and Chief Executive Officer and a director of Cenovus's Board as of November 6, 2017;*
- *Messrs. Kvisle and MacPhail were first elected as directors of Cenovus's Board at the annual meeting of shareholders held on April 25, 2018;*
- *Ms. Kinney was first elected as a director of Cenovus's Board at the annual meeting of shareholders held on April 24, 2019;*
- *Mr. Casey was first elected as a director of Cenovus's Board as of April 29, 2020; and*
- *Mrs. Kwok, and Messrs. Fok, Shaw and Sixt were appointed as directors of Cenovus's Board as of January 1, 2021.*

The term of each of the directors is from the date of the meeting at which he or she is elected or appointed until the next annual meeting of shareholders or until a successor is elected or appointed.

(2) Member of the Audit Committee.
(3) Member of the Human Resources and Compensation Committee.
(4) Member of the Nominating and Corporate Governance Committee.
(5) Member of the Safety, Environment, Responsibility and Reserves Committee.
(6) Ex officio, by standing invitation, non-voting member of the Audit Committee, the Human Resources and Compensation Committee and the Safety, Environment, Responsibility and Reserves Committee. As an ex officio non-voting member, Mr. MacPhail attends as his schedule permits and may vote when necessary to achieve a quorum.
(7) As an officer and a non-independent director, Mr. Pourbaix is not a member of any of the committees of Cenovus's Board.

As at December 31, 2020, Susan F. Dabarno, Steven F. Leer and M. George Lewis were directors of Cenovus. Each of Ms. Dabarno and Messrs. Leer and Lewis were members of the Nominating and Corporate Governance Committee. Messrs. Leer and Lewis were also members of the Human Resources and Compensation Committee and Ms. Dabarno was also a member of the Audit Committee. Each of Ms. Dabarno and Messrs. Leer and Lewis resigned from Cenovus's Board on January 1, 2021, prior to closing of the Husky Arrangement.

EXECUTIVE OFFICERS

The following individuals are the executive officers of Cenovus:

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Alexander J. Pourbaix Calgary, Alberta, Canada	President & Chief Executive Officer Mr. Pourbaix's biographical information is included under "Directors".
Jeffrey R. Hart Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer Mr. Hart was appointed Executive Vice-President & Chief Financial Officer of Cenovus effective January 1, 2021. From November 2018 to January 1, 2021, Mr. Hart was Chief Financial Officer of Husky; from April 2018 to November 2019, Mr. Hart was Acting Chief Financial Officer of Husky; and from February 2015 to April 2018, Mr. Hart was Vice President, Controller of Husky Oil Operations Limited.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Jonathan M. McKenzie Calgary, Alberta, Canada	Executive Vice-President & Chief Operating Officer Mr. McKenzie was appointed Executive Vice-President & Chief Operating Officer of Cenovus effective January 1, 2021. From May 2018 to January 1, 2021, Mr. McKenzie was Executive Vice-President and Chief Financial Officer of Cenovus. From April 2015 to April 2018, Mr. McKenzie was Chief Financial Officer of Husky. From April 2011 to April 2015, Mr. McKenzie was Chief Financial Officer and Chief Commercial Officer of Irving Oil Ltd.; and from March 2009 to May 2011, Mr. McKenzie was Vice-President and Controller of Suncor Energy Inc.
Keith A. Chiasson Calgary, Alberta, Canada	Executive Vice-President, Downstream Mr. Chiasson was appointed Executive Vice-President, Downstream of Cenovus on March 1, 2019. From December 2017 to February 2019, Mr. Chiasson was Senior Vice-President, Downstream of Cenovus; from May 2017 to December 2017, Mr. Chiasson was Vice-President, Oil Sands Production Operations of Cenovus; and from July 2016 to May 2017, Mr. Chiasson was Vice-President, Operations of Cenovus. From April 2016 to July 2016, Mr. Chiasson was Kearl Operations Manager at Imperial Oil Resources; from September 2013 to April 2016, Mr. Chiasson was U.S. Operations Manager for ExxonMobil; and from January 2012 to September 2013, Mr. Chiasson was Planning and Business Analysis Manager for ExxonMobil Production Company.
P. Andrew Dahlin Calgary, Alberta, Canada	Executive Vice-President, Safety & Operations Technical Services Mr. Dahlin was appointed Executive Vice-President, Safety & Operations Technical Services of Cenovus effective January 1, 2021. From November 2020 to January 1, 2021, Mr. Dahlin was Executive Vice-President, Downstream of Husky; from May 2020 to November 2020, Mr. Dahlin was Executive Vice President, Onshore Upstream of Husky; from May 2018 to May 2020, Mr. Dahlin was Senior Vice President, Heavy Oil & Oil Sands of Husky Oil Operations Limited; from June 2017 to May 2018, Mr. Dahlin was Senior Vice President, Heavy Oil of Husky Oil Operations Limited; and from April 2012 to May 2017, Mr. Dahlin was Vice President, Upstream of Husky Oil Operations Limited.
Norrie C. Ramsay Calgary, Alberta, Canada	Executive Vice-President, Upstream – Thermal, Major Projects & Offshore Dr. Ramsay was appointed Executive Vice-President, Upstream – Thermal, Major Projects & Offshore of Cenovus effective January 1, 2021. From January 2020 to January 1, 2021, Dr. Ramsay was Executive Vice-President, Upstream of Cenovus; from December 2019 to January 2020, Dr. Ramsay was Executive Vice-President of Cenovus. From June 2019 to November 2019, Dr. Ramsay was Senior Vice-President, Projects at TC Energy; from August 2014 to May 2019, Dr. Ramsay was Senior Vice-President, Technical Centre & Projects at TC Energy; and from May 2010 to July 2014, Dr. Ramsay was Global Vice-President, Projects & Engineering at Talisman Energy Inc.
Karamjit S. Sandhar Calgary, Alberta, Canada	Executive Vice-President, Strategy & Corporate Development Mr. Sandhar was appointed Executive Vice-President, Strategy & Corporate Development of Cenovus effective January 1, 2021. From January 2020 to January 1, 2021, Mr. Sandhar was Senior Vice-President, Conventional of Cenovus, and Senior Vice-President, Deep Basin of Cenovus prior to the Deep Basin segment being renamed the Conventional segment in the first quarter of 2020. From December 2017 to December 2019, Mr. Sandhar was Senior Vice-President, Strategy & Corporate Development of Cenovus; from July 2016 until December 2017, Mr. Sandhar was Vice-President, Investor Relations & Corporate Development of Cenovus; from May 2016 to July 2016, Mr. Sandhar was Vice-President, Investor Relations of Cenovus; from May 2015 to May 2016, Mr. Sandhar was Director, Investor Relations of Cenovus; and from April 2013 to May 2015 Mr. Sandhar was Principal, Portfolio Management of Cenovus.

Name and Residence	Office Held and Principal Occupation During the Past Five Years
Sarah J. Walters Calgary, Alberta, Canada	Executive Vice-President, Corporate Services Mrs. Walters was appointed Executive Vice-President, Corporate Services of Cenovus effective January 1, 2021. From December 2017 to January 1, 2021, Mrs. Walters was Senior Vice-President, Corporate Services of Cenovus; from January 2017 until December 2017, Mrs. Walters was Vice-President, Human Resources of Cenovus; from September 2015 to December 2016, Mrs. Walters was Vice-President, Organization & People of Cenovus; from March 2014 to August 2015, Mrs. Walters was Vice-President HR Business Partners & Organizational Design of Cenovus; from July 2013 to February 2014, Mrs. Walters was Vice-President, HR Business Partners of Cenovus; and from March 2013 to July 2013, Mrs. Walters was Vice-President, HR Advisory of Cenovus. Prior to joining Cenovus in March 2013, Mrs. Walters was Vice-President HR, International Operations West at Talisman Energy Inc.
J. Drew Zieglgansberger Calgary, Alberta, Canada	Executive Vice-President, Upstream – Conventional & Integration Mr. Zieglgansberger was appointed Executive Vice-President, Upstream – Conventional & Integration of Cenovus effective January 1, 2021. From January 2020 to January 1, 2021, Mr. Zieglgansberger was Executive Vice-President, Strategy & Corporate Development of Cenovus; from January 2018 to December 2019, Mr. Zieglgansberger was Executive Vice-President, Upstream of Cenovus; from April 2017 to January 2018, Mr. Zieglgansberger was Executive Vice-President, Deep Basin of Cenovus; from September 2015 to April 2017, Mr. Zieglgansberger was Executive Vice-President, Oil Sands Manufacturing of Cenovus; from June 2015 to August 2015, Mr. Zieglgansberger was Executive Vice-President, Operations Shared Services of Cenovus; from June 2012 to May 2015, Mr. Zieglgansberger was Senior Vice-President, Operations Shared Services of Cenovus; from January 2012 to May 2012, Mr. Zieglgansberger was Senior Vice-President, Regulatory, Local Community & Military of Cenovus; and from December 2010 to January 2012, Mr. Zieglgansberger was Senior Vice-President, Christina Lake of Cenovus.
Rhona M. DelFrari Calgary, Alberta, Canada	Chief Sustainability Officer & Senior Vice-President, Stakeholder Engagement Ms. DelFrari was appointed Chief Sustainability Officer & Senior Vice-President, Stakeholder Engagement of Cenovus effective January 1, 2021. From June 2017 to January 1, 2021, Ms. DelFrari was Vice-President, Sustainability & Engagement. From January 2012 to June 2017, Ms. DelFrari held various positions within the communications, external relations and strategy portfolios.
Gary F. Molnar Calgary, Alberta, Canada	Senior Vice-President Legal, General Counsel & Corporate Secretary Mr. Molnar was appointed Senior Vice-President Legal, General Counsel & Corporate Secretary of Cenovus effective January 1, 2021. From December 2015 to January 1, 2021, Mr. Molnar was Vice-President, Legal, Assistant General Counsel & Corporate Secretary; from March 2011 to December 2015, Mr. Molnar was Vice-President, Legal & Assistant Corporate Secretary; and from November 2009 to March 2011, Mr. Molnar was Vice-President & Assistant Corporate Secretary of Cenovus.

As at December 31, 2020, Harbir S. Chhina and Alan C. Reid were executive officers of Cenovus. Each of Messrs. Chhina and Reid resigned from his respective office on January 1, 2021, following closing of the Husky Arrangement.

As of December 31, 2020, all of Cenovus's directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 2,817,469 Common Shares or approximately 0.23 percent of the number of Common Shares that were outstanding as of such date. As of February 1, 2021, all of Cenovus's directors and executive officers, as a group, beneficially owned or exercised control or direction over, directly or indirectly, 2,507,805 Common Shares or approximately 0.12 percent of the number of Common Shares that were outstanding as of such date.

Investors should be aware that some of Cenovus's directors and officers are directors and officers of other private and public companies. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships which may create situations in which conflicts might arise. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the CBCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of Cenovus.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

To the Corporation's knowledge, none of its current directors or executive officers are, as at the date of this AIF, or have been, within 10 years prior to the date of this AIF, a director, chief executive officer or chief financial officer of any company that:

(a) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days (each, an "Order") and that was issued while that director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or

(b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

To the Corporation's knowledge, none of its directors or executive officers:

(a) is, as at the date of this AIF, or has been within 10 years prior to the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, within 10 years prior to the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer.

To the Corporation's knowledge, none of its directors or executive officers has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

The Audit Committee mandate is included as Appendix C to this AIF.

COMPOSITION OF THE AUDIT COMMITTEE

The Audit Committee consists of four members, each of whom is independent and financially literate in accordance with National Instrument 52-110 *Audit Committees*. The Board determined that each of the following members of Cenovus's Audit Committee qualifies as an "audit committee financial expert", as that term is defined under U.S. securities legislation: Claude Mongeau and Jane E. Kinney. The education and experience of each of the members of the Audit Committee relevant to the performance of the responsibilities as an Audit Committee member is outlined below.

As at December 31, 2020, the Audit Committee consisted of Claude Mongeau, Jane E. Kinney, Susan F. Dabarno and Harold N. Kvisle. Concurrently with the completion of the Husky Arrangement, Cenovus's Board, and each committee of the Board, were reconstituted, resulting in the current Audit Committee membership.

Claude Mongeau (Audit Committee Chair)

Mr. Mongeau holds a Masters of Business Administration degree from McGill University and has received honorary doctorate degrees from St. Mary's and Windsor University. He is a director of The Toronto-Dominion Bank, an international financial institution, and Norfolk Southern Corporation, a publicly traded rail transportation provider. He served as a director of TELUS Corporation, a publicly traded telecommunications company, from May 2017 to August 2019. He served as a director of Canadian National Railway Company, a publicly traded railroad and transportation company, from October 2009 to July 2016 and as President and Chief Executive Officer from January 2010 to June 2016. During his tenure with Canadian National Railway Company, he served as Executive Vice-President and Chief Financial Officer from October 2000 until December 2009 and from the time he joined Canadian National Railway Company in 1994 he held the titles of Senior Vice-President and Chief Financial Officer, Vice-President, Strategic and Financial Planning and Assistant Vice-President, Corporate Development.

Jane E. Kinney

Ms. Kinney is a chartered professional accountant, a Fellow of the Chartered Professional Accountants of Ontario (FCPA) and holds a Mathematics degree from the University of Waterloo. She is a seasoned business leader with over 30 years of experience in providing advisory services to global financial institutions and has extensive experience in enterprise risk management, regulatory compliance, cyber and IT risk management, digital transformation and stakeholder relations.

Ms. Kinney is a director and Chair of the Audit Committee of Intact Financial Corporation, a publicly traded insurance company. She spent 25 years with Deloitte and was admitted to the Deloitte Partnership in 1997. She was appointed Vice Chair, Leadership Team Member of Deloitte in June 2010 and served in this role until her retirement in June 2019. Previous positions with Deloitte include Canadian Managing Partner, Quality & Risk from May 2010 to June 2015, Global Chief Risk Officer from June 2010 to May 2012, and Risk and Regulatory Practice Leader from June 1999 to May 2010.

Richard J. Marcogliese

Mr. Marcogliese holds a Bachelor of Engineering degree in Chemical Engineering from the New York University School of Engineering and Science. He is the Principal of iRefine, LLC, a privately owned petroleum refining consulting company, and a director of Delek US Holdings, Inc., a publicly traded downstream energy company. He served as Executive Advisor of Pilko & Associates L.P., a private chemical and energy advisory company, from June 2011 to December 2019; Operations Advisor to NTR Partners III LLC, a private investment company from October 2013 to December 2017; and from September 2012 to January 2016 as Operations Advisor to the Chief Executive Officer of Philadelphia Energy Solutions, a partnership between The Carlyle Group and a subsidiary of Energy Transfer Partners, L.P. that operates an oil refining complex on the U.S. Eastern seaboard.

Wayne E. Shaw

Mr. Shaw holds a Bachelor of Arts degree and a Bachelor of Laws degree from the University of Alberta. He is a member of the Law Society of Ontario. He is the President of G.E. Shaw Investments Limited, a private investment holding company. Prior to his retirement in 2013, Mr. Shaw was a Senior Partner with Stikeman Elliott LLP, Barristers and Solicitors, Toronto, Ontario.

The above list does not include Keith A. MacPhail who is, by standing invitation as Chair of the Board, an *ex officio* member of Cenovus's Audit Committee.

PRE-APPROVAL POLICIES AND PROCEDURES

Cenovus has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP. The Audit Committee has established a budget for the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by PricewaterhouseCoopers LLP, the Corporation's auditor. Subject to the Audit Committee's discretion, the budget generally covers the period between the adoption of the budget and the next meeting of the Audit Committee. The list of permitted services is sufficiently detailed to ensure that: (i) the Audit Committee knows precisely what services it is being asked to pre-approve; and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

Subject to the following paragraph, the Audit Committee has delegated authority to the Chair of the Audit Committee (or if the Chair is unavailable, any other member of the Audit Committee) to pre-approve the provision of permitted services by PricewaterhouseCoopers LLP which are not otherwise pre-approved by the Audit Committee, including the fees and terms of the proposed services ("Delegated Authority"). Any required determination about the Chair's unavailability will be required to be made by the good faith judgment of the applicable other member(s) of the Audit Committee after considering all facts and circumstances deemed by such member(s) to be relevant. All pre-approvals granted pursuant to Delegated Authority must be presented by the member(s) who granted the pre-approvals to the full Audit Committee at its next meeting.

The fees payable in connection with any particular service to be provided by PricewaterhouseCoopers LLP that have been pre-approved pursuant to Delegated Authority: (i) may not exceed $200,000, in the case of pre-approvals granted by the Chair of the Audit Committee; and (ii) may not exceed $50,000, in the case of pre-approvals granted by any other member of the Audit Committee.

All proposed services or the fees payable in connection with such services that have not already been pre-approved must be pre-approved by either the Audit Committee or pursuant to Delegated Authority. Prohibited services may not be pre-approved by the Audit Committee or pursuant to Delegated Authority.

EXTERNAL AUDITOR SERVICE FEES

The following table provides information about the fees billed to Cenovus for professional services rendered by PricewaterhouseCoopers LLP in the years ended December 31, 2020 and 2019:

($ thousands)	**2020**	2019
Audit Fees(1)	**2,598**	2,938
Audit-Related Fees(2)	**382**	226
Tax Fees(3)	**128**	2
All Other Fees(4)	**46**	284
Total	**3,154**	3,450

(1) Audit Fees consist of the aggregate fees billed for the audit of the Corporation's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-Related Fees consist of the aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as Audit Fees. The services provided in this category included audit-related services in relation to Cenovus's prospectuses and participation fees levied by the Canadian Public Accountability Board. Fees related to the acquisition or divestiture of assets are also included in Audit-Related Fees.

(3) Tax Fees consist of the aggregate fees billed for tax compliance and tax advice.

(4) All Other Fees include fees billed for the review of Extractive Sector Transparency Measures Act filings , advisory services around Enterprise Resource Planning and the Corporation's Innovation Processes.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

During the year ended December 31, 2020, there were no legal proceedings to which Cenovus is or was a party, or that any of its property is or was the subject of, which involves a claim for damages in an amount, exclusive of interest and costs, that exceeds 10 percent of Cenovus's current assets and it is not aware of any such legal proceedings that are contemplated.

During the year ended December 31, 2020, there were no penalties or sanctions imposed against Cenovus by a court relating to securities legislation or by a securities regulatory authority, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, and it has not entered into any settlement agreements before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Corporation's directors or executive officers or any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10 percent of any class or series of Cenovus's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in each case, as at the date of this AIF, has or has had any material interest, direct or indirect, in any past transaction within the three most recently completed financial years or any proposed transaction that has materially affected or is reasonably expected to materially affect Cenovus.

TRANSFER AGENTS AND REGISTRARS

In Canada:
Computershare Investor Services, Inc.
8th Floor, 100 University Avenue
Toronto, ON M5J 2Y1
Canada

In the United States:
Computershare Trust Company NA
250 Royall St.
Canton, MA 02021
U.S.

Tel: 1-866-332-8898
Website: www.investorcentre.com/cenovus

MATERIAL CONTRACTS

Other than as set forth below, during the year ended December 31, 2020, Cenovus has not entered into any contracts, nor are there any contracts still in effect, that are material to the business, other than contracts entered into in the ordinary course of business.

ConocoPhillips Transaction

On March 29, 2017, Cenovus entered into a purchase and sale agreement (the "COP Acquisition Agreement") with ConocoPhillips to acquire: (i) ConocoPhillips' 50 percent interest (the "FCCL Interest") (being the remaining 50 percent interest that Cenovus did not already own) in FCCL Partnership, the owner of the Foster Creek, Christina Lake and Narrows Lake oil sands projects in northeast Alberta, and (ii) the majority of ConocoPhillips' western Canadian conventional assets, including ConocoPhillips' exploration and production assets and related infrastructure and agreements in the Elmworth-Wapiti, Kaybob-Edson and Clearwater operating areas and other operating areas, and all of ConocoPhillips' interest in petroleum and natural gas rights and oil sands leases within a certain area of mutual interest northwest of Foster Creek (the "Deep Basin Assets"). The FCCL Interest and the Deep Basin Assets

were acquired by Cenovus for total consideration of $17.6 billion, comprised of $15.0 billion cash, and 208 million Common Shares.

At closing of the COP Acquisition Agreement, Cenovus and ConocoPhillips entered into a contingent payment agreement (the "COP Contingent Payment Agreement"), pursuant to which Cenovus agreed to make quarterly payments to ConocoPhillips during the five years subsequent to the closing date of the COP Acquisition Agreement for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. The quarterly payment will be $6 million for each dollar that the WCS price exceeds $52 per barrel. There are no maximum payment terms. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment.

Also, at closing of the COP Acquisition Agreement, Cenovus and ConocoPhillips entered into a registration rights agreement ("COP Registration Rights Agreement") and an investor agreement ("COP Investor Agreement"), which, among other things, restricted ConocoPhillips from selling or hedging its Common Shares until November 17, 2017. In addition, the COP Registration Rights Agreement provides ConocoPhillips with certain rights to facilitate the sale of its Common Shares, including the right to require Cenovus to qualify the distribution of the Common Shares held by ConocoPhillips and the right to piggy-back on an offering of Common Shares by Cenovus. The COP Investor Agreement places certain restrictions on ConocoPhillips, including from nominating new members to Cenovus's board of directors and by requiring ConocoPhillips to vote its Common Shares in accordance with management recommendations or abstain from voting. The COP Registration Rights Agreement and the COP Investor Agreement will terminate when ConocoPhillips owns 3.5 percent or less of the then-outstanding Common Shares.

A copy of the COP Acquisition Agreement, which includes the forms of the COP Contingent Payment Agreement, COP Registration Rights Agreement and COP Investor Agreement, in redacted form, was filed on SEDAR on April 5, 2017, and a copy of the amendment to the COP Acquisition Agreement was filed on SEDAR on May 17, 2017, each of which may be viewed under Cenovus's profile at sedar.com and on EDGAR at sec.gov.

Husky Arrangement Standstill Agreements

On October 24, 2020, each of Hutchison Whampoa Europe Investments S.à r.l. and L.F. Investments S.à r.l. entered into a separate standstill agreement with Cenovus (each, a "Husky Arrangement Standstill Agreement"), with effect as of January 1, 2021. Each Husky Arrangement Standstill Agreement sets forth certain restrictions and obligations in connection with such shareholder's shareholdings in Cenovus following completion of the transactions contemplated by the Husky Arrangement, including but not limited to the following:

a. subject to certain exceptions, without the prior written consent of Cenovus, such shareholder agreed that it will not acquire, agree to acquire or make any proposal or offer to acquire voting or equity securities of Cenovus or any of its subsidiaries (other than Cenovus Warrants), securities convertible into, or exercisable or exchangeable for, voting or equity securities of Cenovus or any of its subsidiaries (other than Cenovus Warrants) or any assets of Cenovus or any of its subsidiaries;

b. for a period of 18 months following January 1, 2021, such shareholder will not transfer or cause the transfer of any Common Shares, except as otherwise permitted by the Husky Arrangement Standstill Agreement (the "Transfer Restrictions");

c. without the prior written consent of Cenovus, such shareholder will not transfer or cause the transfer of, either alone or in the aggregate with its affiliates, the other such shareholder or its affiliates, any Common Shares or Cenovus Warrants to any person, if such transfer would, to the knowledge of the shareholder, result in such person, together with any persons acting jointly or in concert with such person, beneficially owning, or controlling or directing, 20 percent or more of the then-outstanding Common Shares, except (a) transfers effected through an underwritten public offering (including an underwritten public offering undertaken pursuant to the applicable Husky Arrangement Registration Rights Agreement (defined below); (b) transfers effected as a result of the consummation of an arrangement, amalgamation, merger or other similar business combination transaction involving Cenovus which has been approved by a resolution of holders of the Common Shares, or made to an offeror in relation to a take-over bid as set out in the Husky Arrangement Standstill Agreement; or (c) transfers to an affiliate as permitted by the Husky Arrangement Standstill Agreement; and

d. such shareholder is subject to voting restrictions with respect to certain Board matters relating to the election of Cenovus's directors and in connection with any arrangement, amalgamation, merger or other similar business combination transaction involving Cenovus.

The Husky Arrangement Standstill Agreements terminate on the earlier of January 1, 2026, the date on which either of the Husky Arrangement Standstill Agreement is terminated by the written agreement of the parties, provided that the Transfer Restrictions have been complied with under each Husky Arrangement Standstill Agreement, the date on which Hutchison Whampoa Europe Investments S.à r.l. and L.F. Investments S.à r.l., together with their affiliates, cease to beneficially own, or control or direct, in aggregate, at least 10 percent of the then-outstanding Common Shares, or any Qualified Individual (as defined in the Husky Arrangement Standstill Agreements) duly nominated in accordance with the Husky Arrangement Standstill Agreements is not appointed to the Board in accordance with the Husky Arrangement Standstill Agreements.

Copies of the Husky Arrangement Standstill Agreements were filed on SEDAR on November 3, 2020 and may be viewed under Cenovus's profile at sedar.com and on EDGAR at sec.gov.

Husky Arrangement Registration Rights Agreements

On January 1, 2021, Cenovus and each of Hutchison Whampoa Europe Investments S.à r.l. and L.F. Investments S.à r.l. entered into a registration rights agreement (each, a "Husky Arrangement Registration Rights Agreement") which provides such shareholders with certain rights to facilitate the sale of their Common Shares, including the right to require Cenovus to qualify the distribution of the Common Shares held by such shareholders and the right to piggy-back on an offering of Common Shares by Cenovus. These rights are available to such shareholders for a term beginning on July 1, 2022 and ceasing on the earlier of January 1, 2026, the date on which the Husky Arrangement Registration Rights Agreement is terminated by agreement of the parties, the date the holder ceases to, directly or indirectly, beneficially own in aggregate more than 5 percent of the then-outstanding Common Shares, or the date on which the Husky Arrangement Standstill Agreements are terminated.

Copies of the Husky Arrangement Registration Rights Agreements were filed on SEDAR on January 4, 2021 and may be viewed under Cenovus's profile at sedar.com and on EDGAR at sec.gov.

Husky Arrangement Pre-Emptive Rights Agreements

On January 1, 2021, Cenovus and each of Hutchison Whampoa Europe Investments S.à r.l. and L.F. Investments S.à r.l. entered into a pre-emptive rights agreement (each, a "Husky Arrangement Pre-Emptive Rights Agreement") which provides such shareholders with certain rights to allow such shareholder to maintain its pro rata share of the then-outstanding Common Shares. These rights are available to such shareholders for a term beginning on January 1, 2021 and ceasing on the earlier of January 1, 2026, the date on which the Husky Arrangement Pre-Emptive Rights Agreement is terminated by agreement of the parties, the date the shareholder ceases to, directly or indirectly, beneficially own in aggregate more than 5 percent of the then-outstanding Common Shares, or the date on which the Husky Arrangement Standstill Agreements are terminated.

Copies of the Husky Arrangement Pre-Emptive Rights Agreements were filed on SEDAR on January 4, 2021 and may be viewed under Cenovus's profile at sedar.com and on EDGAR at sec.gov.

Warrant Indenture

At closing of the Husky Arrangement, the Cenovus Warrants were created and issued pursuant to the terms of the Warrant Indenture entered into with Computershare Trust Company of Canada, as warrant agent, which governs the Cenovus Warrants. The Warrant Indenture provides for customary adjustments to the number of Common Shares issuable upon exercise of the Cenovus Warrants and/or to the exercise price in effect for the Cenovus Warrants, and for adjustment in the class and/or number of securities issuable upon exercise of the Cenovus Warrants and/or to the exercise price for the Cenovus Warrants, upon the occurrence of certain events. Cenovus also covenants in the Warrant Indenture that, so long as any Cenovus Warrant remains outstanding, Cenovus will give notice to holders of Cenovus Warrants of certain stated events, including events that would result in an adjustment to the exercise price for the Cenovus Warrants or the number of Common Shares issuable upon exercise of the Cenovus Warrants, at least 10 business days prior to the record date of such event.

A copy of the Warrant Indenture was filed on SEDAR on January 4, 2021 and may be viewed under Cenovus's profile at sedar.com and on EDGAR at sec.gov.

INTERESTS OF EXPERTS

The Corporation's independent auditors are PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued an independent auditor's report dated February 8, 2021 in respect of Cenovus's Consolidated Financial Statements which comprise the Consolidated Balance Sheets as at December 31, 2020 and December 31, 2019 and the Consolidated Statements of Earnings (Loss), Comprehensive Income, Shareholders' Equity and Cash Flows for the years ended December 31, 2020, 2019, and 2018 and Cenovus's internal control over financial reporting as at December 31, 2020. PricewaterhouseCoopers LLP has advised that they are independent with respect to Cenovus within the meaning of the Code of Professional Conduct of the Chartered Professional Accountants of Alberta and the rules of the SEC.

Information relating to Cenovus's reserves in this AIF has been calculated by McDaniel and GLJ as independent qualified reserves evaluators. The partners, employees or consultants of each of McDaniel and GLJ, in each case, as a group own beneficially, directly or indirectly, less than one percent of any class of the Corporation's outstanding securities.

ADDITIONAL INFORMATION

Additional information relating to Cenovus is available on SEDAR at sedar.com and EDGAR at sec.gov. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Cenovus's securities, and securities authorized for issuance under its equity-based compensation plans, is included in the Corporation's management information circular for its most recent annual meeting of shareholders.

Additional financial information concerning Cenovus as at December 31, 2020 can be found in Cenovus's audited annual Consolidated Financial Statements and MD&A for the year ended December 31, 2020.

As a Canadian corporation listed on the NYSE, Cenovus is not required to comply with most of the NYSE's corporate governance standards, and instead may comply with Canadian corporate governance practices. However, the Corporation is required to disclose the significant differences between its corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. Except as summarized on Cenovus's website at cenovus.com, it is in compliance with the NYSE corporate governance standards in all significant respects.

ACCOUNTING MATTERS

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars. All references to "dollars", "C$" or to "$" are to Canadian dollars and all references to "US$" are to U.S. dollars. The information contained in this AIF is dated as at December 31, 2020 unless otherwise indicated. Numbers presented are rounded to the nearest whole number and tables may not add due to rounding.

Unless otherwise indicated, all financial information included in this AIF has been prepared in accordance with International Financial Reporting Standards, which are also generally accepted accounting principles for publicly accountable enterprises in Canada.

ABBREVIATIONS AND CONVERSIONS

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	AECO	Alberta Energy Company
bbls/d	barrels per day	Bcf	billion cubic feet
Mbbls/d	thousand barrels per day	Mcf	thousand cubic feet
MMbbls	million barrels	MMcf	million cubic feet
NGLs	natural gas liquids	MMcf/d	million cubic feet per day
BOE	barrel of oil equivalent	MMBtu	million British thermal units
BOE/d	barrels of oil equivalent per day		
MMBOE	million barrels of oil equivalent		
WTI	West Texas Intermediate		
WCS	Western Canadian Select		

In this AIF, certain natural gas volumes have been converted to BOE on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

APPENDIX A

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the Board of Directors of Cenovus Energy Inc. (the "Corporation"):

1. We have evaluated the Corporation'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 Corporation'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 percent, included in the reserves data of the Corporation evaluated for the year ended December 31, 2020, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's Board of Directors:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves	Evaluated Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) $ millions
McDaniel & Associates Consultants Ltd.	December 31, 2020	Canada	$30,796
GLJ Ltd.	December 31, 2020	Canada	$1,114
			$31,910

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

7. We have no responsibility to update our reports referred to in paragraph five for events and circumstances occurring after their respective effective dates.

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:

/s/ Brian R. Hamm

Brian R. Hamm, P. Eng.
President & CEO
McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

/s/ Jodi L. Anhorn

Jodi L. Anhorn, M.Sc., P. Eng.
President and Chief Executive Officer
GLJ Ltd.
Calgary, Alberta, Canada

February 8, 2021

APPENDIX B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Cenovus Energy Inc. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. A report from the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Safety, Environment, Responsibility and Reserves Committee of the Board of Directors of the Corporation has:

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

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

(c) reviewed the reserves data with management and each of the independent qualified reserves evaluators.

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

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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

/s/ Alexander J. Pourbaix

Alexander J. Pourbaix
President & Chief Executive Officer

/s/ Jeffrey R. Hart

Jeffrey R. Hart
Executive Vice-President &
Chief Financial Officer

/s/ Keith A. MacPhail

Keith A. MacPhail
Director and Chair of the Board

/s/ Richard J. Marcogliese

Richard J. Marcogliese
Director and Chair of the Safety, Environment, Responsibility and Reserves Committee

February 8, 2021

APPENDIX C

AUDIT COMMITTEE MANDATE

PURPOSE

The Audit Committee (the "Committee") is a committee of the Board of Directors (the "Board") of Cenovus Energy Inc. ("Cenovus" or the "Corporation") appointed to assist the Board in fulfilling its oversight responsibilities.

The Committee's primary duties and responsibilities are to:

- Oversee and monitor the effectiveness and integrity of the Corporation's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting compliance.
- Oversee audits of the Corporation's financial statements.
- Review and evaluate the Corporation's risk management framework and related processes including the supporting guidelines and practice documents.
- Review and approve management's identification of principal financial risks and monitor the process to manage such risks.
- Oversee and monitor the Corporation's compliance with legal and regulatory requirements.
- Oversee and monitor the qualifications, independence and performance of the Corporation's external auditors and internal auditing group.
- Provide an avenue of communication among the external auditors, management, the internal auditing group, and the Board.
- Report to the Board regularly.

The Committee has the authority to conduct any review or investigation appropriate to fulfilling its responsibilities. The Committee shall have unrestricted access to personnel and information, and any resources necessary to carry out its responsibility. In this regard, the Committee may direct internal audit personnel to particular areas of examination.

CONSTITUTION, COMPOSITION AND DEFINITIONS

1. Reporting

The Committee shall report to the Board.

2. Composition

The Committee shall consist of not less than three and not more than eight directors as determined by the Board, all of whom shall qualify as independent directors pursuant to National Instrument 52-110 Audit Committees (as implemented by the Canadian Securities Administrators ("CSA") and as amended from time to time) ("NI 52-110").

All members of the Committee shall be financially literate, as defined in NI 52-110, and at least one member shall have accounting or related financial managerial expertise. In particular, at least one member shall have, through (i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions; (ii) experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions; (iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or (iv) other relevant experience:

- An understanding of accounting principles and financial statements;
- The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;
- Experience preparing, auditing, analyzing or evaluating 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, or experience actively supervising one or more persons engaged in such activities;

- An understanding of internal controls and procedures for financial reporting; and
- An understanding of audit committee functions.

Committee members may not, other than in their respective capacities as members of the Committee, the Board or any other committee of the Board, accept directly or indirectly any consulting, advisory or other compensatory fee from the Corporation or any subsidiary of the Corporation, or be an "affiliated person" (as such term is defined in the *United States Securities Exchange Act of 1934*, as amended (the "Exchange Act"), and the rules, if any, adopted by the U.S. Securities and Exchange Commission ("SEC") thereunder) of the Corporation or any subsidiary of the Corporation. For greater certainty, directors' fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation that are not contingent on continued service should be the only compensation an Audit Committee member receives from the Corporation.

At least one member shall have experience in the oil and gas industry.

Committee members shall not simultaneously serve on the audit committees of more than two other public companies, unless the Board first determines that such simultaneous service will not impair the ability of the relevant members to effectively serve on the Committee, and required public disclosure is made.

The non-executive Board Chair shall be a non-voting member of the Committee. See "Quorum" for further details.

3. Appointment of Committee Members

Committee members shall be appointed by the Board, effective after the election of directors at the annual meeting of shareholders, provided that any member may be removed or replaced at any time by the Board and shall, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board.

4. Vacancies

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

5. Chair

The Nominating and Corporate Governance Committee will recommend for approval to the Board an independent Director to act as Chair of the Committee. The Board shall appoint the Chair of the Committee.

If unavailable or unable to attend a meeting of the Committee, the Chair shall ask another member to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen to preside over the meeting by a majority of the members of the Committee present at such meeting.

The Chair presiding at any meeting of the Committee shall not have a casting vote.

The items pertaining to the Chair in this section should be read in conjunction with the Committee Chair section of the Chair of the Board of Directors and Committee Chair General Guidelines.

6. Secretary

The Committee shall appoint a Secretary who need not be a member of the Committee. The Secretary shall keep minutes of the meetings of the Committee.

7. Meetings

The Committee shall meet at least quarterly. The Chair of the Committee may call additional meetings as required. In addition, a meeting may be called by the non-executive Board Chair, the Chief Executive Officer, or any member of the Committee or by the external auditors.

Committee meetings may, by agreement of the Chair of the Committee, be held in person, by video conference, by means of telephone or by a combination of any of the foregoing.

The Committee shall meet without the presence of management on a regular basis, to facilitate additional open and candid discussion among independent directors.

8. Notice of Meeting

Notice of the time and place of each Committee meeting may be given orally, or in writing, or by facsimile, or by electronic means to each member of the Committee at least 24 hours prior to the time fixed for such meeting. Notice of each meeting shall also be given to the external auditors of the Corporation.

A member and the external auditors may, in any manner, waive notice of the Committee meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

9. Quorum

A majority of Committee members, present in person, by video conference, by telephone, or by a combination thereof, shall constitute a quorum. In addition, if an ex officio, non-voting member's presence is required to attain a quorum of the Committee, then the said member shall be allowed to cast a vote at the meeting.

10. Attendance at Meetings

The Chief Executive Officer, the Chief Financial Officer, the Comptroller and the head of internal audit are expected to be available to attend the Committee's meetings or portions thereof.

The Committee may, by specific invitation, have other resource persons in attendance.

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Committee Chair or by a majority of the members of the Committee.

11. Minutes

Minutes of each Committee meeting should be succinct yet comprehensive in describing substantive issues discussed by the Committee. However, they should clearly identify those items of responsibilities scheduled by the Committee for the meeting that have been discharged by the Committee and those items of responsibilities that are outstanding.

Minutes of Committee meetings shall be sent to all Committee members and to the external auditors. The full Board of Directors shall be kept informed of the Committee's activities by a report following each Committee meeting.

RESPONSIBILITIES

In carrying out its mandate, the Committee is expected to:

12. Review Procedures

(a) Review and update the Committee's mandate annually, or sooner if the Committee deems it appropriate to do so. Review the summary of the Committee's composition and responsibilities in the Corporation's annual report, annual information form or other public disclosure documentation.

(b) Review the summary of all approvals by the Committee of the provision of audit, audit-related, tax and other services by the external auditors for inclusion in the Corporation's annual report and Annual Information Form filed with the CSA and the SEC.

13. Annual Financial Statements

(a) Discuss and review with management and the external auditors the Corporation's and any subsidiary with public securities' annual audited financial statements and related documents prior to their filing or distribution. Such review shall include:

(i) The annual financial statements and related notes including significant issues regarding accounting principles, practices and significant management estimates and judgments,

including any significant changes in the Corporation's selection or application of accounting principles, any major issues as to the adequacy of the Corporation's internal controls and any special steps adopted in light of material control deficiencies.

(ii) Management's Discussion and Analysis.

(iii) The use of off-balance sheet financing including management's risk assessment and adequacy of disclosure.

(iv) The external auditors' audit examination of the financial statements and their report thereon.

(v) Any significant changes required in the external auditors' audit plan.

(vi) Any serious difficulties or disputes with management encountered during the course of the audit, including any restrictions on the scope of the external auditors' work or access to required information.

(vii) Other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

(b) Review and formally recommend approval to the Board of the Corporation's:

(i) Year-end audited financial statements. Such review shall include discussions with management and the external auditors as to:

i. The accounting policies of the Corporation and any changes thereto.
ii. The effect of significant judgments, accruals and estimates.
iii. The manner of presentation of significant accounting items.
iv. The consistency of disclosure.

(ii) Management's Discussion and Analysis.

(iii) Annual Information Form as to financial information.

(iv) All prospectuses and information circulars as to financial information.

The review shall include a report from the external auditors about the quality of the most critical accounting principles upon which the Corporation's financial status depends, and which involve the most complex, subjective or significant judgmental decisions or assessments.

14. Quarterly Financial Statements

(a) Review with management and the external auditors and either approve (such approval to include the authorization for public release) or formally recommend for approval to the Board the Corporation's:

(i) Quarterly unaudited financial statements and related documents, including Management's Discussion and Analysis.

(ii) Any significant changes to the Corporation's accounting principles.

(b) Review quarterly unaudited financial statements prior to their distribution of any subsidiary of the Corporation with public securities.

15. Other Financial Filings and Public Documents

Review and discuss with management financial information, including earnings press releases, the use of "pro forma" or non-GAAP financial information and earnings guidance, contained in any filings with the CSA or SEC or press releases related thereto, and consider whether the information is consistent with the information contained in the financial statements of the Corporation or any subsidiary with public securities.

16. Internal Control Environment

(a) Receive and review from management, the external auditors and the internal auditors an annual report on the Corporation's control environment as it pertains to the Corporation's financial reporting process and controls.

(b) Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Corporation.

(c) Review in consultation with the internal auditors and the external auditors the degree of coordination in the audit plans of the internal auditors and the external auditors and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud, or other illegal acts. The Committee will assess the coordination of audit effort to assure completeness of coverage and the effective use of audit resources. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

(d) Review with the Chief Executive Officer, the Chief Financial Officer of the Corporation and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Corporation's internal controls and procedures for financial reporting which could adversely affect the Corporation's ability to record, process, summarize and report financial information required to be disclosed by the Corporation in the reports that it files or submits under the Exchange Act or applicable Canadian federal and provincial legislation and regulations within the required time periods, and (ii) any fraud, whether or not material, that involves management of the Corporation or other employees who have a significant role in the Corporation's internal controls and procedures for financial reporting.

(e) Review significant findings prepared by the external auditors and the internal auditing department together with management's responses.

17. Risk Oversight

Review and evaluate the Corporation's risk management framework and related processes including the supporting guidelines and practice documents.

18. Other Review Items

(a) Review the process for the certification of the interim and annual financial statements by the Chief Executive Officer and Chief Financial Officer, and the certifications made by the Chief Executive Officer and Chief Financial Officer.

(b) Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets, and consider the results of any review of these areas by the internal auditor or the external auditors.

(c) Review all related party transactions between the Corporation and any executive officers or directors, including affiliations of any executive officers or directors.

(d) Review with the General Counsel, the head of internal audit and the external auditors the results of their review of the Corporation's monitoring of compliance with each of the Corporation's published codes of business conduct and applicable legal requirements.

(e) Review legal and regulatory matters, including correspondence with and reports received from regulators and government agencies, that may have a material impact on the interim or annual financial statements and related corporate compliance policies and programs. Members from the Legal and Tax groups should be at the meeting in person to deliver their respective reports.

(f) Review policies and practices with respect to off-balance sheet transactions and trading and hedging activities, and consider the results of any review of these areas by the internal auditors or the external auditors.

(g) Ensure that the Corporation's presentation of hydrocarbon reserves has been reviewed with the Safety, Environment, Responsibility and Reserves Committee of the Board.

(h) Review management's processes in place to prevent and detect fraud.

(i) Review:

(i) procedures for the receipt, retention and treatment of complaints received by the Corporation, including confidential, anonymous submissions by employees of the Corporation, regarding accounting, internal accounting controls, or auditing matters; and

(ii) a summary of any significant investigations regarding such matters.

(j) Meet on a periodic basis separately with management.

19. External Auditors

(a) Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Corporation. The external auditors shall report directly to the Committee.

(b) Meet on a regular basis with the external auditors (without management present) and have the external auditors be available to attend Committee meetings or portions thereof at the request of the Chair of the Committee or by a majority of the members of the Committee.

(c) Review and discuss a report from the external auditors at least quarterly regarding:

- (i) All critical accounting policies and practices to be used;
- (ii) All alternative treatments within accounting principles for policies and practices related to material items that have been discussed with management, including the ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and
- (iii) Other material written communications between the external auditors and management, such as any management letter or schedule of unadjusted differences.

(d) Obtain and review a report from the external auditors at least annually regarding:

- (i) The external auditors' internal quality-control procedures.
- (ii) Any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with those issues.
- (iii) To the extent contemplated in the following paragraph, all relationships between the external auditors and the Corporation.

(e) Review and discuss at least annually with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (i) receiving and reviewing, as part of the report described in the preceding paragraph, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation and its affiliates, (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (iii) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.

(f) Review and evaluate annually:

- (i) The external auditors' and the lead partner of the external auditors' team's performance, and make a recommendation to the Board of Directors regarding the reappointment of the external auditors at the annual meeting of the Corporation's shareholders or regarding the discharge of such external auditors.
- (ii) The terms of engagement of the external auditors together with their proposed fees.
- (iii) External audit plans and results.
- (iv) Any other related audit engagement matters.
- (v) The engagement of the external auditors to perform non-audit services, together with the fees therefor, and the impact thereof, on the independence of the external auditors.
- (vi) Review the Annual Report of the Canadian Public Accountability Board ("CPAB") concerning audit quality in Canada and discuss implications for Cenovus.

(vii) Review any reports issued by CPAB regarding the audit of Cenovus.

(g) Conduct periodically a comprehensive review of the external auditor, with the outcome intended to assist the Committee to identify potential areas for improvement for the audit firm, and to reach a final conclusion on whether the auditor should be reappointed or the audit put out for tender.

(h) Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 19.(c) through (f), evaluate the external auditors' qualifications, performance and independence, including whether or not the external auditors' quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining auditor independence, taking into account the opinions of management and the head of internal audit. The Committee shall present to the Board its conclusions in this respect.

(i) Review the rotation of partners on the audit engagement team in accordance with applicable law. Consider whether, in order to assure continuing external auditor independence, it is appropriate to adopt a policy of rotating the external auditing firm on a regular basis.

(j) Set clear hiring policies for the Corporation's hiring of employees or former employees of the external auditors.

(k) Consider with management and the external auditors the rationale for employing audit firms other than the principal external auditors.

(l) Consider and review with the external auditors, management and the head of internal audit:

(i) Significant findings during the year and management's responses and follow-up thereto.
(ii) Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management's response.
(iii) Any significant disagreements between the external auditors or internal auditors and management.
(iv) Any changes required in the planned scope of their audit plan.
(v) The resources, budget, reporting relationships, responsibilities and planned activities of the internal auditors.
(vi) The internal audit department mandate.
(vii) Internal audit's compliance with the Institute of Internal Auditors' standards.

20. Internal Audit Group and Independence

(a) Meet on a periodic basis separately with the head of internal audit.

(b) Review and concur in the appointment, compensation, replacement, reassignment, or dismissal of the head of internal audit.

(c) Review with the head of internal audit the Internal Audit budget, resource plan, activities, organizational structure of the internal audit function and the qualifications of the internal auditors.

(d) Confirm and assure, annually, the independence of the internal audit group.

(e) Approve the Internal Audit Charter, and the annual Internal Audit Plan.

(f) Review the performance and effectiveness of the Internal Audit function including conformance with The Institute of Internal Auditors' International Standards for the Professional Practice of Internal Auditing and the Code of Ethics.

21. Approval of Audit and Non-Audit Services

(a) Review and, where appropriate, approve the provision of all permitted non-audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors (subject to the de minimus exception for non-audit services described in the Exchange Act or applicable CSA and SEC legislation and regulations, which services are approved by the Committee prior to the completion of the audit).

(b) Review and, where appropriate and permitted, approve the provision of all audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors.

(c) If the pre-approvals contemplated in paragraphs 21.(a) and (b) are not obtained, approve, where appropriate and permitted, the provision of all audit and non-audit services promptly after the Committee or a member of the Committee to whom authority is delegated becomes aware of the provision of those services.

(d) Delegate, if the Committee deems necessary or desirable, to subcommittees consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 21.(a) through (c). The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

(e) Establish policies and procedures for the pre-approvals described in paragraphs 21.(a) and (b) so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation to management of the Committee's responsibilities under the Exchange Act or applicable CSA and SEC legislation and regulations.

22. Other Matters

(a) Review and concur in the appointment, replacement, reassignment, or dismissal of the Chief Financial Officer.

(b) Upon a majority vote of the Committee outside resources may be engaged where and if deemed advisable.

(c) Report Committee actions to the Board of Directors with such recommendations as the Committee may deem appropriate.

(d) Conduct or authorize investigations into any matters within the Committee's scope of responsibilities. The Committee shall be empowered to retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and the carrying out of its duties.

(e) Determine the appropriate funding for payment by the Corporation (i) of compensation to the external auditors for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation, (ii) of compensation to any advisors employed by the Committee, and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

(f) Review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Nominating and Corporate Governance Committee for consideration and, if appropriate, recommendation to the Board for approval.

(g) Consider for implementation any recommendations of the Nominating and Corporate Governance Committee of the Board with respect to the Committee's effectiveness, structure, processes or mandate.

(h) Perform such other functions as required by law, the Corporation's by-laws or the Board of Directors.

(i) Consider any other matters referred to it by the Board of Directors.

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board.

Revised Effective: February 8, 2021

APPENDIX D

NETBACK RECONCILIATIONS

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold. Netbacks reflect Cenovus's margin on a per-barrel basis of unblended bitumen and crude oil. As such, the bitumen and crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the bitumen and heavy crude oil to reduce its thickness in order to transport it to market. Cenovus's Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook.

The following tables provide a reconciliation of the financial components comprising Netbacks (in millions of dollars) to the nearest GAAP measure found in the annual and interim consolidated financial statements.

Year ended December 31, 2020
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands(1)	Conventional(1)	Total Upstream
Revenues			
Gross Sales	7,514	635	**8,149**
Less: Royalties	324	40	**364**
	7,190	595	**7,785**
Expenses			
Transportation and Blending	4,399	81	**4,480**
Operating	1,094	318	**1,412**
Inventory Write-Down (Reversal)	316	-	**316**
Netback	1,381	196	**1,577**
(Gain) Loss on Risk Management	268	-	**268**
Operating Margin	1,113	196	**1,309**

	Basis of Netback Calculation					Adjustments			Per Above Table
	Bitumen	Heavy Crude Oil	Light and Medium Oil	NGLs	Natural Gas	Condensate	Inventory(2)	Other	Total Upstream
Gross Sales	4,053	30	71	157	328	3,452	-	58	**8,149**
Royalties	330	1	11	15	13	-	(6)	-	**364**
Transportation and Blending	1,232	2	5	30	44	3,452	(285)	-	**4,480**
Operating	1,109	9	18	65	203	-	(25)	33	**1,412**
Inventory Write-Down (Reversal)	-	-	-	-	-	-	316	-	**316**
Netback	1,382	18	37	47	68	-	-	25	**1,577**
(Gain) Loss on Risk Management									**268**
Operating Margin									**1,309**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Three months ended December 31, 2020
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands[1]	Conventional[1]	Total Upstream
Revenues			
Gross Sales	2,227	184	**2,411**
Less: Royalties	131	12	**143**
	2,096	172	**2,268**
Expenses			
Transportation and Blending	1,131	18	**1,149**
Operating	309	72	**381**
Inventory Write-Down (Reversal)	-	-	**-**
Netback	656	82	**738**
(Gain) Loss on Risk Management	40	-	**40**
Operating Margin	616	82	**698**

	Basis of Netback Calculation					Adjustments			Per Above Table
	Bitumen	Heavy Crude Oil	Light and Medium Oil	NGLs	Natural Gas	Condensate	Inventory[2]	Other	Total Upstream
Gross Sales	1,371	6	18	47	99	853	-	17	**2,411**
Royalties	131	-	3	8	1	-	-	-	**143**
Transportation and Blending	278	-	1	7	10	853	-	-	**1,149**
Operating	306	2	3	15	45	-	-	10	**381**
Inventory Write-Down (Reversal)	-	-	-	-	-	-	-	-	**-**
Netback	656	4	11	17	43	-	-	7	**738**
(Gain) Loss on Risk Management									**40**
Operating Margin									**698**

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Three months ended September 30, 2020
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands[1]	Conventional[1]	Total Upstream
Revenues			
Gross Sales	2,195	156	**2,351**
Less: Royalties	129	24	**153**
	2,066	132	**2,198**
Expenses			
Transportation and Blending	1,015	21	**1,036**
Operating	276	81	**357**
Inventory Write-Down (Reversal)	-	-	**-**
Netback	775	30	**805**
(Gain) Loss on Risk Management	137	-	**137**
Operating Margin	638	30	**668**

	Basis of Netback Calculation					Adjustments			Per Above Table
	Bitumen	Heavy Crude Oil	Light and Medium Oil	NGLs	Natural Gas	Condensate	Inventory[2]	Other	Total Upstream
Gross Sales	1,447	11	20	36	78	747	-	12	**2,351**
Royalties	129	1	2	12	9	-	-	-	**153**
Transportation and Blending	274	1	2	7	11	747	(6)	-	**1,036**
Operating	274	2	4	17	53	-	-	7	**357**
Inventory Write-Down (Reversal)	-	-	-	-	-	-	-	-	**-**
Netback	770	7	12	-	5	-	6	5	**805**
(Gain) Loss on Risk Management									**137**
Operating Margin									**668**

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Three months ended June 30, 2020
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands[1]	Conventional[1]	Total Upstream
Revenues			
Gross Sales	1,065	133	**1,198**
Less: Royalties	20	1	**21**
	1,045	132	**1,177**
Expenses			
Transportation and Blending	649	19	**668**
Operating	224	81	**305**
Inventory Write-Down (Reversal)	(19)	-	**(19)**
Netback	191	32	**223**
(Gain) Loss on Risk Management	66	-	**66**
Operating Margin	125	32	**157**

	Basis of Netback Calculation					Adjustments			Per Above Table
	Bitumen	Heavy Crude Oil	Light and Medium Oil	NGLs	Natural Gas	Condensate	Inventory[2]	Other	Total Upstream
Gross Sales	425	3	11	34	73	639	-	13	**1,198**
Royalties	26	-	2	(3)	2	-	(6)	-	**21**
Transportation and Blending	289	-	1	7	12	639	(279)	(1)	**668**
Operating	248	2	5	17	52	-	(25)	6	**305**
Inventory Write-Down (Reversal)	-	-	-	-	-	-	(19)	-	**(19)**
Netback	(138)	1	3	13	7	-	329	8	**223**
(Gain) Loss on Risk Management									**66**
Operating Margin									**157**

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

Three months ended March 31, 2020
($ millions)

	Per Consolidated Financial Statements		
	Oil Sands[1]	Conventional[1]	Total Upstream
Revenues			
Gross Sales	2,027	162	**2,189**
Less: Royalties	44	3	**47**
	1,983	159	**2,142**
Expenses			
Transportation and Blending	1,604	23	**1,627**
Operating	285	84	**369**
Inventory Write-Down (Reversal)	335	-	**335**
Netback	(241)	52	**(189)**
(Gain) Loss on Risk Management	25	-	**25**
Operating Margin	(266)	52	**(214)**

	Basis of Netback Calculation					Adjustments			Per Above Table
	Bitumen	Heavy Crude Oil	Light and Medium Oil	NGLs	Natural Gas	Condensate	Inventory[2]	Other	Total Upstream
Gross Sales	810	10	22	40	78	1,213	-	16	**2,189**
Royalties	44	-	4	(2)	1	-	-	-	**47**
Transportation and Blending	391	1	1	9	11	1,213	-	1	**1,627**
Operating	281	3	6	16	53	-	-	10	**369**
Inventory Write-Down (Reversal)	-	-	-	-	-	-	335	-	**335**
Netback	94	6	11	17	13	-	(335)	5	**(189)**
(Gain) Loss on Risk Management									**25**
Operating Margin									**(214)**

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold.

The following table provides the sales volumes used to calculate Netback.

Sales Volumes

(barrels per day, unless otherwise stated)	2020	Q4	Q3	Q2	Q1
Bitumen					
Foster Creek	**164,906**	161,108	158,280	171,139	169,207
Christina Lake	**221,675**	220,676	238,140	198,954	228,764
Total Bitumen	**386,581**	381,784	396,420	370,093	397,971
Crude Oil (Heavy, Light and Medium) and NGLs					
Heavy Crude Oil	**2,640**	1,922	3,087	1,981	3,576
Light and Medium Oil	**4,493**	4,263	4,318	4,309	5,086
NGLs	**19,513**	18,358	18,297	20,320	21,104
Total Bitumen, Crude Oil (Heavy, Light and Medium) and NGLs Sales	**413,227**	406,327	422,122	396,703	427,737
Natural Gas Sales (MMcf/d)**(1)**	**380**	371	360	392	395
Total Sales (BOE/d)	**476,488**	468,249	482,133	462,068	493,529

(1) Includes volume sold between segments.

Exhibit 99.2



MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE PERIOD ENDED DECEMBER 31, 2020

OVERVIEW OF CENOVUS 1
LOW OIL PRICES AND THE NOVEL CORONAVIRUS ("COVID-19") 2
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This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) as at December 31, 2020 and, for greater certainty, unless otherwise specified or the context otherwise requires, excludes Husky Energy Inc. ("Husky") and the subsidiaries of, and partnership interests held by Husky and its subsidiaries, dated February 8, 2021, should be read in conjunction with our December 31, 2020 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 8, 2021, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 8, 2021. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

On January 1, 2021, pursuant to a plan of arrangement under the Business Corporations Act (Alberta), Husky became a wholly-owned subsidiary of Cenovus. In connection with its acquisition of Husky and in accordance with applicable securities laws, Cenovus will be filing a business acquisition report containing the pro forma financial statements of the combined company as of December 31, 2020. Additional information concerning Husky's business and assets as of December 31, 2020 may be found in the annual information form of Husky dated February 8, 2021 for the year ended December 31, 2020 (the "Husky AIF") and Husky's management's discussion and analysis of the financial and operating results for the year ended December 31, 2020 (the "Husky MD&A"), each of which is filed and available on SEDAR under Husky's profile at sedar.com.

Basis of Presentation

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, (which includes references to "dollar" or "$"), except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

Non-GAAP Measures and Additional Subtotals

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Netbacks, Adjusted Funds Flow, Operating Earnings, Free Funds Flow, Net Debt, Capitalization and Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. In addition, Operating Margin is considered an additional subtotal found in Note 1 of our Consolidated Financial Statements. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to

finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

The definition and reconciliation, if applicable, of each non-GAAP measure or additional subtotal is presented in the Operating and Financial Results, Liquidity and Capital Resources, or Advisory sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian-based integrated oil and natural gas company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. At December 31, 2020, prior to the close of the transaction with Husky on January 1, 2021, as described below, our operations included oil sands projects in northeast Alberta and established crude oil, natural gas liquids ("NGLs") and natural gas production in Alberta and British Columbia. Total production from our upstream assets averaged approximately 472,000 BOE per day in 2020. We also conducted marketing activities and have ownership interest in refining operations in the United States ("U.S."). The refineries processed an average of 372,000 gross barrels per day of crude oil feedstock into an average of 385,000 gross barrels per day of refined products in 2020.

For a description of our operations in 2020, refer to the Reportable Segments section of this MD&A.

Cenovus and Husky Arrangement

On October 24, 2020, Cenovus and Husky entered into a definitive agreement to combine the two companies in an all-stock transaction to create a resilient Canadian-based integrated energy company. The transaction was accomplished through a plan of arrangement ("the Arrangement") pursuant to which Cenovus acquired all the issued and outstanding common shares of Husky in exchange for common shares and common share purchase warrants of Cenovus. In addition, all of the issued and outstanding Husky preferred shares were exchanged for Cenovus preferred shares with substantially identical terms. The Arrangement closed on January 1, 2021 and we continue to operate as Cenovus, trade under the Cenovus name, and remain headquartered in Calgary, Alberta.

The Arrangement combines high quality oil sands and heavy oil assets with extensive trading, supply and logistics infrastructure, and downstream infrastructure, creating opportunities to optimize the margin captured across the heavy oil value chain. With the combination of processing capacity and market access outside Alberta for the majority of the Company's oil sands and heavy oil production, exposure to Alberta heavy oil price differentials is reduced while maintaining exposure to global commodity prices. The combined company has a cost-and-market-advantaged asset portfolio, which prioritizes free funds flow generation, balance sheet strength and returns to shareholders.

The combined company is the third largest Canadian oil and natural gas producer and the second largest Canadian-based refiner and upgrader with operations in Canada, the U.S. and the Asia Pacific region. Our operations include oil sands projects in northern Alberta, thermal and conventional crude oil and natural gas projects across Western Canada, crude oil production offshore Newfoundland and Labrador and natural gas and liquids production offshore China and Indonesia. Our downstream operations include upgrading, refining and marketing operations in Canada and the U.S.

Management is in the process of finalizing the determination of the operating and reporting segments for the Company. It is anticipated that the Company's business will be conducted predominately through an upstream and downstream segment. Management continues to evaluate how the segments may be presented and will make a final determination during the first quarter of 2021.

The Upstream business is anticipated to be reported as follows:

- **Oil Sands,** includes the development and production of heavy oil and bitumen in northeast Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Christina Lake, Sunrise and Tucker oil sands projects, as well as Lloydminster Thermal and Cold and Enhanced Oil Recovery assets.
- **Conventional,** includes the operations from conventional oil and natural gas production, including processing operations in the Deep Basin and other parts of Western Canada.
- **Offshore,** includes the offshore operations, exploration and development activities in the Asia Pacific region and Atlantic Canada region.

The Downstream business is anticipated to be reported under the following segments:

- **Canadian Manufacturing,** includes Cenovus's owned and operated upgrader and asphalt refinery in Lloydminster, the owned and operated crude-by-rail terminal and two ethanol plants.
- **Retail,** includes the Canadian retail, commercial and wholesale channels.
- **U.S. Manufacturing,** includes the U.S. operations of wholly owned refineries in Lima and Superior, the jointly owned Wood River and Borger refineries with operator Phillips 66 and the jointly owned Toledo refinery with BP Products North America Inc. as operator.

Our Strategy

Our strategy remains focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. Our diverse and integrated portfolio will help us to deliver stable cash flow through price cycles while maintaining safe and reliable operations. We remain focused on sustainably growing shareholder returns and reducing Net Debt. The diverse portfolio of projects and other opportunities across our business are expected to allow us to leverage increased economies of scale to better compete in an increasingly consolidated energy industry. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility. We plan to use our capital allocation framework to evaluate disciplined investments in our portfolio against dividends, share repurchases and managing to the optimal debt level while maintaining investment grade status. Our investment focus will be on areas where we believe we have the greatest competitive advantage to generate the highest returns and incorporate Environmental, Social and Governance ("ESG") considerations into our business plan.

On January 28, 2021 we announced the 2021 budget for the combined company focused on sustaining capital and generating free funds flow to strengthen the balance sheet, accelerated by capturing transaction-related synergies across the organization. 2021 guidance dated January 28, 2021 is available on our website at cenovus.com.

Additional information on the Arrangement is available in our news releases, dated October 25, 2020 and January 4, 2021 available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com, in our joint management information circular with Husky dated November 9, 2020 available on SEDAR and EDGAR, and in our material change reports dated November 3, 2020 and January 11, 2021 available on SEDAR and EDGAR. The information in this MD&A, as it relates to our operations for 2020, does not reflect the closing of the Arrangement, unless otherwise noted.

LOW OIL PRICES AND THE NOVEL CORONAVIRUS ("COVID-19")

2020 was a challenging year due to the significant decrease in crude oil demand due to COVID-19 resulting in the low global oil price environment.

During the first half of the year, there was a significant reduction in crude oil demand as a result of measures taken by governments around the world to contain the COVID-19 pandemic. At the same time, overall global crude oil supply increased as efforts between the Organization of Petroleum Exporting Countries ("OPEC") and non-OPEC members, primarily Saudi Arabia and Russia, to manage global crude oil production levels broke down and each party increased their daily crude production. The combination of these events resulted in a collapse of crude oil benchmark prices, dropping to a low of US$10.01 per barrel, excluding a historic one-day low of negative US$37.63 per barrel on April 20, 2020.

In light of these unprecedented conditions, we reduced our planned capital investment plan, operating costs, and general and administrative ("G&A") costs. We remained focused on enhancing our financial resilience and financial capability to maintain our base business and deliver safe and reliable operations.

In April, the agreement between OPEC and a group of 10 non-OPEC members (collectively, "OPEC+") to cut crude oil output, and several other countries announcing similar production cuts decreased the global supply of crude oil. At the same time, governments began to ease off on some of the measures taken to contain the pandemic increasing demand for crude oil, which helped increase crude oil prices.

In the second half of 2020, crude oil prices improved from the low prices impacting the first half of the year; however, prices continued to be volatile due to market responses to COVID-19 and OPEC crude oil production output decisions. Volatility of crude oil prices continued in the fourth quarter, responding to news of COVID-19 vaccine breakthroughs, continued OPEC and OPEC+ output restrictions, and government responses to the resurgence of COVID-19 cases.

We believe that we have ample liquidity and runway to sustain our operations through a prolonged market downturn. Following the closing of the Arrangement on January 1, 2021, Cenovus has $8.5 billion in committed credit facilities, with $2.0 billion maturing in June 2022, $1.2 billion maturing in November 2022, $3.3 billion maturing in November 2023, and $2.0 billion maturing in March 2024. Under the terms of Cenovus's committed credit facilities, the Company is required to maintain a debt to capitalization ratio, as defined in the agreement governing the credit facilities, not to exceed 65 percent. As at December 31, 2020, the Company was well below this limit and we expect to continue to be in compliance with all financial covenants under the credit facilities.

The Provincial and Federal governments have recognized the serious economic impacts of COVID-19 and have taken steps to provide various programs, such as the Canada Emergency Wage Subsidy ("CEWS") program. During the year we continued to benefit from the assistance of the CEWS program to help protect jobs during the pandemic.

The Company remains committed to the health and safety of its workforce and the public while providing essential services. Physical distancing measures continue to be taken to maintain the health and safety of our people and to help mitigate the risk of COVID-19 at our workplaces. We continue to monitor the changing COVID-19 situation and respond accordingly in a timely manner. In October, we lifted our mandatory work from home measure,

implemented in March, to open our modified workspaces in the Calgary offices to staff again, with workplace safety plans and protocols in place. However, due to rising COVID-19 cases in November this was scaled back and office staff are once again required to work from home. Mandatory work-from-home measures are now in place for all non-essential staff at our combined offices and worksites in Alberta, Saskatchewan and Manitoba until the end of March 2021, pending further review. Our U.S. and Atlantic Canada locations will continue to take direction from local health authorities regarding their COVID-19 workplace mandates. Staff levels at sites and offices have and will continue to follow guidance received from the applicable federal, provincial, state and local governments and public health officials.

YEAR IN REVIEW

During 2020, operating variables under Management's control performed well. We focused on delivering value through preserving financial resilience. Throughout the year, we demonstrated our ability to use our full suite of assets to maximize prices received for every barrel as we adjusted our Oil Sands production rates in response to price signals and stored volumes in a low-price environment and cleared inventory when we could obtain higher prices. We also remained focused on maintaining our low cost structure.

Operationally, our upstream assets performed well. Our upstream production averaged 471,740 BOE per day in 2020, compared with 451,680 BOE per day in 2019. In 2020 we managed our production to optimal levels, producing above the Government of Alberta's mandatory production curtailment as we purchased additional credits. As of December 2020, monthly oil production limits are no longer in effect and the Government of Alberta will give 30 to 60 days' notice if production limits are put back into place.

The Wood River and Borger refineries (the "Refineries") demonstrated reliable operational performance while operating below capacity for the majority of the year due to economic crude rate reductions in response to lower refined product demand and weak market crack spreads.

Throughout 2020, Management continued to focus on maintaining our low operating and capital cost structure.

Crude oil prices were volatile throughout the year due to demand and supply impacts as a result of COVID-19 and OPEC and non-OPEC members production level commitments. West Texas Intermediate ("WTI") benchmark crude oil prices ranged from a high of US$63.27 per barrel to a low of US$10.01 per barrel and averaged 31 percent lower than 2019. Western Canadian Select ("WCS") benchmark prices averaged US$26.80 per barrel, 39 percent lower than US$44.27 per barrel in 2019. Our average realized crude oil sales price of $28.82 per barrel decreased significantly compared with $53.95 per barrel in 2019 due to declining benchmark WTI prices.

As noted, COVID-19 had a significant impact on our results.

- Our first quarter results were impacted by measures taken to contain COVID-19 and the over-supply of crude oil. We responded by announcing reductions to our capital spending, operating and G&A costs, and temporarily suspended our dividend. Average WTI and WCS crude oil benchmark prices for the first quarter declined to US$46.17 per barrel and US$25.64 per barrel, respectively, which had a significant impact on our first quarter results with asset impairment charges of $318 million, a Net Loss of $1,797 million and our operating margin was negative $589 million;
- The second quarter was a transition period for the market. Crude oil prices were severely impacted, with WCS averaging a low of US$3.50 per barrel in April. This was followed by a steady strengthening of crude oil prices with WCS averaging US$33.97 per barrel in June, caused by the easing of some of the restrictions imposed by governments to limit the spread of COVID-19 combined with the commitment by OPEC and non-OPEC members to reduce crude oil production levels in response to lower demand and low commodity prices. We responded to price signals, managing our Oil Sands production by reducing production rates in April and successfully ramped up production in May and June, to achieve peak production rates, when pricing was more favourable. Our Net Loss of $235 million improved in the second quarter compared with the first quarter and our operating margin was $291 million, demonstrating some momentum in economic recovery;
- Our results in the third quarter gradually improved along with the improvement in crude oil prices. WTI and WCS averaged US$40.93 per barrel and US$31.84 per barrel, respectively, in the third quarter. However, crude oil prices remained low as the second wave of COVID-19 infections drove uncertainty. Operationally, our upstream assets continued to perform well and in response to increasing crude oil prices, we purchased production curtailment credits available in the market to produce above our curtailment limit and sold crude oil inventory that had built up when crude oil prices were lower. Our Net Loss of $194 million, which included impairments and write-downs of $521 million, continued to improve quarter over quarter and operating margin of $594 million more than doubled that of the second quarter of 2020. In the third quarter we used the proceeds from the issuance of US$1.0 billion in 5.375 percent senior unsecured notes due in 2025 to repay short-term borrowings; and
- Our fourth quarter results were mixed as COVID-19 infection rates, global economic performance and speculation on vaccine development impacted the pace of crude oil demand recovery with WTI and WCS averaging US$42.66 per barrel and US$33.36 per barrel, respectively. Our fourth quarter Net Loss of $153 million decreased and operating margin of $625 million increased compared with the third quarter of

2020, and we recognized $298 million in impairments and write-downs. Net income also included a $100 million loss related to the Keystone XL pipeline project. We exited the year with Net Debt of $7.2 billion.

In 2020, upstream operating margin of $1,309 million decreased compared with $3,723 million in 2019, due to a lower average realized crude oil sales price, the use of higher priced condensate in a declining market earlier in the year, partially offset by lower royalties and higher sales volumes.

Our Refining and Marketing segment generated operating margin of negative $388 million, down from $737 million in 2019 primarily due to decreased market crack spreads, lower crude advantage and reduced crude oil runs, partially offset by lower operating costs.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results

	2020	Percent Change	2019	Percent Change	2018
Upstream Production Volumes					
Oil Sands (barrels per day)					
Foster Creek	**163,210**	**2**	159,598	(1)	161,979
Christina Lake	**218,513**	**12**	194,659	(3)	201,017
Total Oil Sands Crude Oil	**381,723**	**8**	354,257	(2)	362,996
Conventional (1) (BOE per day)	**89,932**	**(8)**	97,423	(19)	120,258
Total Production from Continuing Operations (BOE per day)	**471,740**	**4**	451,680	(7)	483,458
Production From Discontinued Operations (BOE per day)	**-**	**-**	-	(100)	294
Sales from Continuing Operations (2) (BOE per day)	**420,456**	**8**	390,813	(10)	436,163
Oil and Gas Reserves (MMBOE)					
Proved	**5,030**	**(1)**	5,103	(1)	5,167
Probable	**1,656**	**(6)**	1,768	(3)	1,821
Proved plus Probable	**6,686**	**(3)**	6,871	(2)	6,988
Refining and Marketing					
Crude Oil Runs (3) (Mbbls/d)	**372**	**(16)**	443	(1)	446
Refined Product (3) (Mbbls/d)	**385**	**(17)**	466	(1)	470
Crude Utilization (3) (percent)	**75**	**(17)**	92	(5)	97
Crude-by-Rail (barrels per day)					
Crude-by-Rail Loads (4)	**30,422**	**(43)**	53,345	1,197	4,113
Crude-by-Rail Sales (5)	**33,870**	**(30)**	48,626	1,367	3,314

(1) This segment was previously referred to as the Deep Basin segment.
(2) Less natural gas volumes used for internal consumption by the Oil Sands segment.
(3) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.
(4) Represents volumes transported outside of Alberta.
(5) Represents volumes sold outside of Alberta.

Upstream Production Volumes

Oil Sands production for 2020 reflects production above our curtailment limit as we managed to optimal production levels by purchasing production curtailment credits. In 2019, our production was in line with the Government of Alberta's mandatory production curtailment program and impacted by a planned turnaround at Christina Lake during the second quarter of 2019.

Conventional production in 2020 decreased to 89,932 BOE per day compared with 97,423 BOE per day in 2019, due to natural declines, partially offset by Marten Hills heavy oil production prior to its disposition, as well as fewer shut-ins for low commodity pricing. Prior to the disposition, Marten Hills production averaged approximately 2,800 barrels per day.

Oil and Gas Reserves

Based on our reserves reports prepared by independent qualified reserves evaluators ("IQREs"), at the end of 2020 we had total proved reserves and total proved plus probable reserves of approximately 5.0 billion BOE and 6.7 billion BOE, respectively, decreases of one percent and three percent compared with 2019. As a result of the close of the Arrangement on January 1, 2021, including reported reserves from Husky, our total proved reserves

and total proved plus probable reserves are anticipated to increase by approximately 1.2 billion BOE and 1.8 billion BOE, respectively.

Additional information about our reserves is included in the Oil and Gas Reserves section of this MD&A.

Refining and Marketing

Crude oil runs and refined product output decreased in 2020 as both Refineries implemented crude rate reductions in response to reduced demand as a result of COVID-19. The economic crude rate reductions in 2020 had a greater impact than the operational performance impacts from unplanned outages, planned maintenance and turnaround activities at the Refineries in 2019.

Further information on the changes in our financial and operating results can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management and Risk Factors section of this MD&A and in the notes to the Consolidated Financial Statements.

Selected Consolidated Financial Results

Market factors such as falling crude oil prices, low market crack spreads, and volatile blending costs were the primary drivers of our financial results. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	**2020**	**Percent Change**	2019	Percent Change	2018 (1)
Operating Margin (2) (3)	**921**	**(79)**	4,460	86	2,394
Cash From (Used in) Operating Activities					
From Continuing Operations	**273**	**(92)**	3,285	55	2,118
Total	**273**	**(92)**	3,285	53	2,154
Adjusted Funds Flow (4)	**147**	**(96)**	3,702	115	1,721
Operating Earnings (loss) (2) (4)	**(2,604)**	**(671)**	456	117	(2,755)
Per Share ($) (5)	**(2.12)**	**(673)**	0.37	117	(2.24)
Net Earnings (Loss)					
From Continuing Operations	**(2,379)**	**(208)**	2,194	175	(2,916)
Per Share ($) (5)	**(1.94)**	**(209)**	1.78	175	(2.37)
Total	**(2,379)**	**(208)**	2,194	182	(2,669)
Per Share ($) (5)	**(1.94)**	**(209)**	1.78	182	(2.17)
Total Assets	**32,770**	**(7)**	35,173	-	35,174
Total Long-Term Financial Liabilities (6)	**9,041**	**7**	8,483	(1)	8,602
Capital Investment (7)	**841**	**(28)**	1,176	(14)	1,363
Dividends					
Cash Dividends	**77**	**(70)**	260	6	245
Per Share ($)	**0.0625**	**(71)**	0.2125	6	0.2000

(1) On January 1, 2019, we adopted IFRS 16, "Leases" ("IFRS 16"), using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in our 2019 annual MD&A.

(2) Represented on a continuing basis.

(3) Additional subtotal found in Note 1 of the Consolidated Financial Statements and defined in this MD&A.

(4) Non-GAAP measure defined in this MD&A. The comparative periods have been reclassified to conform with the current period treatment of non-cash inventory write-downs and reversals.

(5) Represented on a basic and diluted per share basis.

(6) Includes Long-Term Debt, Lease Liabilities, Contingent Payment Liabilities and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.

(7) Includes expenditures on property, plant and equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

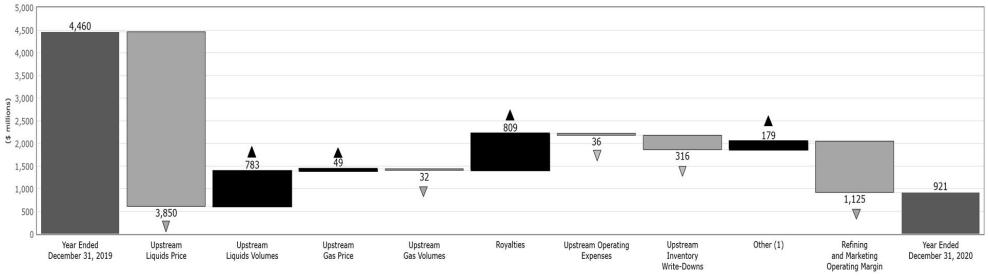
Operating Margin

Operating Margin is an additional subtotal found in Note 1 of the Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, inventory write-downs, net of reversals, plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin.

($ millions)	2020	2019 (1) (2)	2018 (2)
Gross Sales	**14,200**	22,042	22,113
Less: Royalties	**364**	1,173	546
Revenues	**13,836**	20,869	21,567
Expenses			
Purchased Product	**5,397**	8,795	9,201
Transportation and Blending	**4,480**	5,234	5,969
Operating Expenses	**2,236**	2,324	2,367
Inventory Write-Down (Reversal)	**555**	49	60
Realized (Gain) Loss on Risk Management Activities	**247**	7	1,576
Operating Margin	**921**	4,460	2,394

(1) The comparative period has been reclassified to conform with the current period treatment of non-cash inventory write-downs and reversals.
(2) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Operating Margin Variance



(1) Other includes the net effect of the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Operating Margin decreased in 2020 primarily due to:

- A 47 percent decline in our average crude oil sales price resulting from lower WTI and WCS benchmark pricing;
- Lower Operating Margin from our Refining and Marketing segment primarily due to reduced market crack spreads, lower crude advantage and reduced crude oil runs, partially offset by lower operating costs; and
- The use of higher priced condensate in a declining market earlier in the year.

These decreases in Operating Margin were partially offset by:

- Lower royalties due to lower realized prices;
- Higher liquids sales volumes; and
- A decrease in transportation and blending expenses due to lower priced condensate used for blending.

Additional details explaining the changes in Operating Margin can be found in the Reportable Segments section of this MD&A.

Cash From (Used in) Operating Activities and Adjusted Funds Flow

Adjusted Funds Flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Adjusted Funds Flow is defined as cash from (used in) operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Non-cash working capital is composed of accounts receivable, inventories (excluding non-cash inventory write-downs and reversals), income tax receivable, accounts payable and income tax payable. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

($ millions)	2020	2019	2018 (1)
Cash From (Used in) Operating Activities	**273**	3,285	2,154
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(72)**	(84)	(72)
Net Change in Non-Cash Working Capital (2)	**198**	(333)	505
Adjusted Funds Flow (2)	**147**	3,702	1,721

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(2) The comparative period has been reclassified to conform with the current period treatment of non-cash inventory write-downs and reversals.

Cash From Operating Activities and Adjusted Funds Flow decreased significantly in 2020, primarily due to lower Operating Margin, as discussed above, transaction costs of $29 million related to the Arrangement, and higher finance costs. The decrease was partially offset by funding from the CEWS program and a current tax recovery of $13 million compared with current tax expense of $17 million. Adjusted Funds Flow was further reduced by a $100 million loss related to the Keystone XL pipeline project. The change in non-cash working capital in 2020 was primarily due to a decrease in inventory and accounts receivable, partially offset by a decrease in accounts payable.

In 2019, the change in non-cash working capital was primarily due to an increase in accounts receivable and inventory, partially offset by an increase in accounts payable and a decrease in income tax receivable.

Operating Earnings (Loss)

Operating Earnings (Loss) is a non-GAAP measure used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings (Loss) is defined as Earnings (Loss) Before Income Tax excluding gain (loss) on discontinuance, revaluation gain, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before income tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

($ millions)	2020	2019	2018 (1)
Earnings (Loss), Before Income Tax	**(3,230)**	1,397	(3,926)
Add (Deduct):			
Unrealized Risk Management (Gain) Loss (2)	**56**	149	(1,249)
Non-Operating Unrealized Foreign Exchange (Gain) Loss (3)	**(194)**	(787)	593
(Gain) Loss on Divestiture of Assets	**(81)**	(2)	795
Operating Earnings (Loss), Before Income Tax	**(3,449)**	757	(3,787)
Income Tax Expense (Recovery)	**(845)**	301	(1,032)
Total Operating Earnings (Loss)	**(2,604)**	456	(2,755)

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(2) Includes the reversal of unrealized (gains) losses recorded in prior periods.
(3) Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.

We incurred an Operating Loss in 2020, relative to Operating Earnings in 2019, primarily due to lower Cash From Operating Activities and Adjusted Funds Flow, as discussed above, higher Depletion, Depreciation and Amortization ("DD&A") including impairment charges of $1,112 million, and operating unrealized foreign exchange losses of $63 million compared with gains of $27 million in 2019. The increase in our Operating Loss was partially offset by non-operating realized foreign exchange gains of $33 million compared with realized losses of $401 million in 2019 on our unsecured notes, a re-measurement gain of $80 million on the contingent payment compared with a loss of $164 million in 2019, and lower non-cash employee long-term incentive costs.

Net Earnings (Loss)

($ millions)	2020 vs. 2019	2019 vs. 2018 (1)
Net Earnings (Loss), Comparative Year	**2,194**	**(2,916)**
Increase (Decrease) due to:		
Operating Margin	**(3,539)**	**2,066**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**93**	**(1,398)**
Unrealized Foreign Exchange Gain (Loss)	**(696)**	**1,476**
Re-measurement of Contingent Payment	**244**	**(114)**
Gain (Loss) on Divestiture of Assets	**79**	**797**
Expenses (2)	**416**	**573**
DD&A	**(1,215)**	**(118)**
Exploration Expense	**(9)**	**2,041**
Income Tax Recovery (Expense)	**54**	**(213)**
Net Earnings (Loss), End of Year	**(2,379)**	**2,194**

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

(2) Includes Corporate and Eliminations realized risk management (gains) losses, general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net, Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

Net Loss of $2,379 million was significantly lower than Net Earnings of $2,194 million in 2019 due to lower Operating Earnings, as discussed above, and non-operating unrealized foreign exchange gains of $194 million compared with $787 million in 2019 partially offset by unrealized risk management losses of $56 million in 2020 compared with losses of $149 million in 2019 and a gain of $79 million on the divestiture of the Marten Hills assets.

Capital Investment

($ millions)	2020	2019 (1)	2018 (2)
Oil Sands	**427**	656	870
Conventional (3)	**78**	103	228
Refining and Marketing	**276**	280	208
Corporate and Eliminations	**60**	137	57
Capital Investment (4)	**841**	1,176	1,363

(1) In the first quarter of 2020, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment, prior to the divestiture in December 2020. The comparative information has been reclassified.

(2) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

(3) This segment was previously referred to as the Deep Basin segment.

(4) Includes expenditures on PP&E and E&E assets.

Capital investment in 2020 decreased compared with 2019, reflecting our reduced capital investment program and revised budget announced in April. Our upstream capital investment focused primarily on sustaining programs. Our downstream capital expenditures focused primarily on yield enhancement, reliability and maintenance projects, as well as storage infrastructure projects.

Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Key performance drivers for our financial results include commodity prices, quality and location price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows selected market benchmark prices and the U.S./Canadian dollar average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates (1)

(US$/bbl, unless otherwise indicated)	Q4 2020	Q4 2019	2020	Percent Change	2019	2018
Brent						
Average	**45.24**	62.50	**43.21**	**(33)**	64.18	71.53
WTI						
Average	**42.66**	56.96	**39.40**	**(31)**	57.03	64.77
Average Differential Brent-WTI	**2.58**	5.54	**3.81**	**(47)**	7.15	6.76
WCS at Hardisty ("WCS")						
Average	**33.36**	41.13	**26.80**	**(39)**	44.27	38.46
Average Differential WTI-WCS	**9.30**	15.83	**12.60**	**(1)**	12.76	26.31
Average (C$/bbl)	**43.41**	54.29	**35.59**	**(39)**	58.77	49.81
WCS at Nederland						
Average	**40.36**	51.47	**35.86**	**(35)**	55.56	62.05
Average Differential WTI-WCS at Nederland	**2.30**	5.49	**3.54**	**141**	1.47	2.72
West Texas Sour ("WTS")						
Average	**43.02**	57.26	**39.37**	**(30)**	56.27	57.24
Average Differential WTI-WTS	**(0.36)**	(0.30)	**0.03**	**(96)**	0.76	7.53
Condensate (C5 @ Edmonton)						
Average	**42.54**	53.01	**37.16**	**(30)**	52.86	61.00
Average Differential WTI-Condensate (Premium)/Discount	**0.12**	3.95	**2.24**	**(46)**	4.17	3.77
Average Differential WCS-Condensate (Premium)/Discount	**(9.18)**	(11.88)	**(10.36)**	**21**	(8.59)	(22.54)
Average (C$/bbl)	**55.36**	69.97	**49.44**	**(30)**	70.15	79.02
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**47.31**	64.83	**45.24**	**(36)**	70.55	77.96
Chicago Ultra-low Sulphur Diesel ("ULSD")	**54.21**	78.09	**50.08**	**(36)**	77.97	86.75
Refining Margin: Average 3-2-1 Crack Spreads (2)						
Chicago	**7.05**	12.27	**7.54**	**(53)**	16.00	15.97
Group 3	**7.57**	14.60	**8.67**	**(48)**	16.67	16.74
Average Natural Gas Prices						
AECO (3) (C$/Mcf)	**2.77**	2.34	**2.24**	**38**	1.62	1.53
NYMEX (US$/Mcf)	**2.66**	2.50	**2.08**	**(21)**	2.63	3.09
Foreign Exchange Rate (US$ per C$1)						
Average	**0.768**	0.758	**0.746**	**(1)**	0.754	0.772
End of Period	**0.785**	0.770	**0.785**	**2**	0.770	0.733

(1) These benchmark prices are not our realized sales prices and represent approximate values. For our average realized sales prices and realized risk management results, refer to the Netback tables in the Reportable Segments section of this MD&A.

(2) The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.

(3) Alberta Energy Company ("AECO") natural gas monthly index.

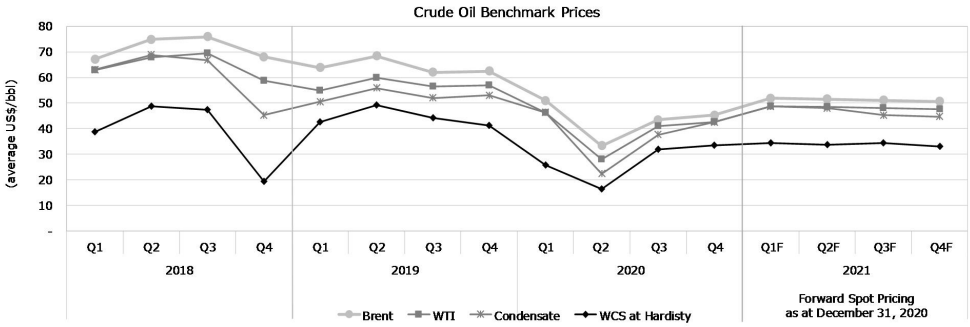
Crude Oil and Condensate Benchmarks

In 2020, the demand for crude oil was under pressure due to COVID-19 while OPEC-led production cuts reduced the impact of the demand destruction resulting in lower average Brent and WTI crude oil benchmark prices.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and the Canadian dollar equivalent is the basis for determining royalty rates for a number of our crude oil properties. In 2020, the Brent-WTI differential narrowed compared with 2019 due to lower exports of crude oil from North America and reduced U.S. crude oil supply.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. In 2020, the WTI-WCS at Hardisty differential narrowed slightly compared with 2019 as reduced Western Canadian Sedimentary Basin ("WCSB") crude supply resulted in excess pipeline capacity for parts of the year, reducing the need for more expensive crude-by-rail shipments. This resulted in average differentials being similar to 2019 when the Government of Alberta enforced their mandatory production curtailment limits.

WCS at Nederland is a heavy oil benchmark at the U.S. Gulf Coast (“USGC”) which is representative of pricing for our sales in the USGC. WCS at Nederland crude oil prices weakened in 2020, consistent with falling crude oil prices globally as refiners lowered crude runs to adjust to reduced demand for products. In 2020, WCS at Nederland benchmark prices relative to WTI widened compared with 2019. The widening was mainly attributed to very wide differentials in the second quarter of 2020 when demand was weak and OPEC+ had not yet committed to production cuts. OPEC+ production cuts are weighed towards medium and heavy sour grades and have resulted in narrower heavy differentials at the USGC in the second half of 2020 compared with the same period of 2019.



WTS is an important North American crude oil benchmark, representing the heavier, more sour counterpart to WTI crude oil, and is a primary component of the input feedstock at the Borger refinery. The average differential between WTI and WTS benchmark prices narrowed in 2020 as debottlenecking of transportation constraints resulted in WTS trading in a narrow range around parity with WTI pricing since early 2019.

Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, diluent volumes as a percentage of total blended volumes, range from approximately 25 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a wider differential generally results in a decrease in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by USGC condensate prices plus the cost to transport the condensate to Edmonton. Our blending costs are also impacted by the timing of purchases and deliveries of condensate into inventory to be available for use in blending as well as timing of sales of blended product.

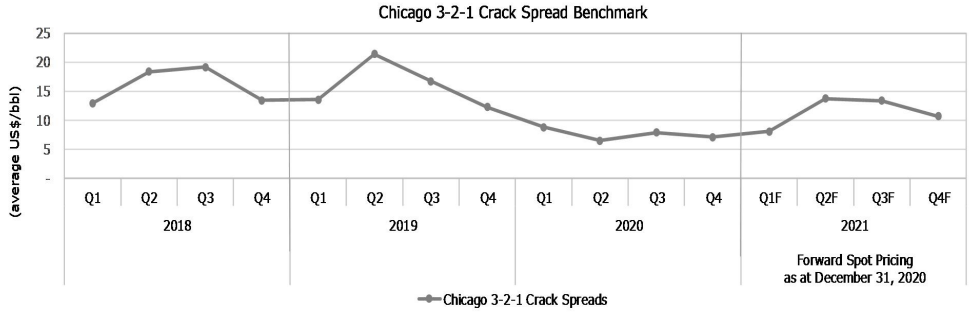
Average condensate benchmark prices were at a narrower discount relative to WTI in Alberta in 2020 as a result of weaker diluent demand due to shut-in heavy oil production offset by lower imported barrels from the U.S. and strong global demand.

Refining Benchmarks

The Chicago Regular Unleaded Gasoline (“RUL”) and Chicago Ultra-low Sulphur Diesel (“ULSD”) benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI-based crude oil feedstock prices and valued on a last in, first out accounting basis.

Average Chicago refined product prices decreased in 2020, primarily due to lower refined product demand as a result of COVID-19. Weaker refined product demand resulted in higher inventory levels which put pressure on market crack spreads. As North American refining crack spreads are expressed on a WTI basis, while refined products are set by global prices, the weakening of refining market crack spreads in the U.S. Midwest and Midcontinent will reflect the differential between Brent and WTI benchmark prices.

Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock, which is valued on a first in, first out (“FIFO”) accounting basis.



Natural Gas Benchmarks

Average AECO prices strengthened in 2020 compared with 2019 as the differential between AECO and NYMEX narrowed significantly due to lower than expected supply, ample access to domestic storage injections and lower pipeline utilization in the WCSB. Average NYMEX prices decreased compared with 2019 due to lower demand and a large decrease in liquified natural gas exports.

Foreign Exchange Benchmark

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, NGLs, natural gas and refined products are determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar compared with the U.S. dollar has a negative impact on our reported results. Likewise, as the Canadian dollar weakens, there is a positive impact on our reported results. In addition to our revenues being denominated in U.S. dollars, our long-term debt is also U.S. dollar denominated. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars.

The Canadian dollar on average weakened relative to the U.S. dollar in 2020, compared with 2019, resulting in a positive impact of approximately $140 million on our revenues in 2020. The strengthening of the Canadian dollar relative to the U.S. dollar as at December 31, 2020 compared with December 31, 2019, resulted in unrealized foreign exchange gains of $194 million on the translation of our U.S. dollar debt.

REPORTABLE SEGMENTS

Our reportable segments at December 31, 2020 are:

Oil Sands, which includes the development and production of bitumen in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as other projects in the early stages of development.

Conventional, which includes assets rich in NGLs and natural gas within the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas in Alberta and British Columbia and the exploration for heavy oil in the Marten Hills area. The assets include interests in numerous natural gas processing facilities. We renamed our Deep Basin segment to Conventional in 2020 and our new resource play, Marten Hills, was reclassified from the Oil Sands segment to the Conventional segment. Comparative periods have been reclassified. On December 2, 2020, we completed the sale of our Marten Hills assets with a retained Gross Overriding Royalty agreement.

Refining and Marketing, which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.

Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Company's rail terminal, crude oil production used as feedstock by the Refining and Marketing segment, and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices.

Revenues by Reportable Segment

($ millions)	**2020**	2019	2018
Oil Sands	**7,190**	9,695	9,553
Conventional (1)	**595**	661	831
Refining and Marketing	**6,051**	10,513	11,183
Corporate and Eliminations	**(609)**	(689)	(724)
	13,227	20,180	20,843

(1) This segment was previously referred to as the Deep Basin segment.

Oil Sands revenues decreased due to lower average realized liquids sales prices, partially offset by lower royalties and higher sales volumes.

Conventional revenues decreased due to lower average realized liquids sales prices, lower natural gas sales volumes and higher royalties, partially offset by a higher average natural gas sales price and the commencement of heavy oil production from our Marten Hills assets prior to its divestiture.

Refining and Marketing revenues declined in 2020. Refining revenues decreased due to lower refined product pricing consistent with the decline in average refined product benchmark prices and lower refined product output due to the economic crude rate reductions. Revenues from third-party crude oil and natural gas sales undertaken by our marketing group decreased compared with 2019 due to lower crude oil prices and lower volumes, partially offset by higher natural gas prices.

Corporate and Eliminations revenues relate to sales of natural gas or crude oil and operating revenues between segments and are recorded at transfer prices based on current market prices.

Overall, revenues declined slightly in 2019 compared with 2018, primarily due to lower refined product pricing and lower upstream sales volumes, partially offset by higher realized crude oil pricing.

OIL SANDS

In 2020, we:

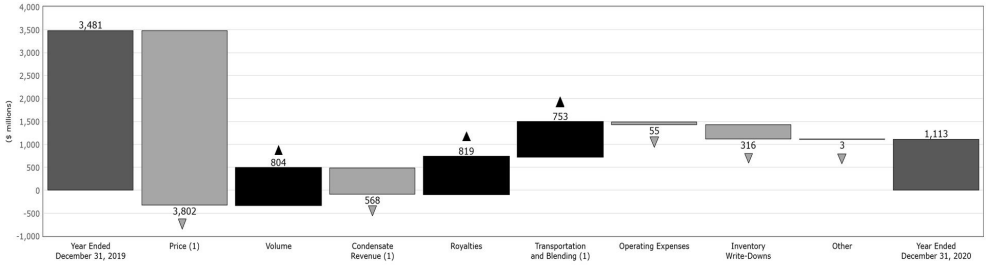
- Delivered safe and reliable operations;
- Increased our Oil Sands production rates to average 381,723 barrels per day;
- Demonstrated our ability to use our full suite of assets to maximize prices received for every barrel as we managed to store volumes in a low-price environment and cleared inventory when we could obtain higher prices; and
- Generated Operating Margin of $1,113 million, a decrease of $2,368 million compared with 2019 due to lower average realized sales prices, partially offset by lower royalties, higher volumes and lower transportation and blending costs.

Financial Results

($ millions)	**2020**	2019	2018 (1)
Gross Sales	**7,514**	10,838	10,026
Less: Royalties	**324**	1,143	473
Revenues	**7,190**	9,695	9,553
Expenses			
Transportation and Blending	**4,399**	5,152	5,879
Operating	**1,094**	1,039	1,037
Inventory Write-Down (Reversal)	**316**	-	-
(Gain) Loss on Risk Management	**268**	23	1,551
Operating Margin	**1,113**	3,481	1,086
Depreciation, Depletion and Amortization	**1,684**	1,543	1,439
Exploration Expense	**9**	18	6
Segment Income (Loss)	**(580)**	1,920	(359)

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Operating Margin Variance



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Revenues

Price

In 2020, our realized crude oil sales price was $28.64 per barrel compared with $53.78 per barrel in 2019, consistent with the overall declines in crude oil benchmark pricing led by a decrease in WTI average benchmark price, partially offset by the lower cost of condensate with an average price of US$37.16 per barrel (2019 – US$52.86 per barrel). The decrease in our crude oil price also reflects the wider WCS-Condensate premium of US$10.36 per barrel (2019 – premium of US$8.59 per barrel). In 2020, COVID-19 impacts resulted in low WTI-WCS differentials during periods of the year resulting in more volumes sold in Alberta compared with 2019, which decreased our realized sales prices. In 2019, we sold more than 25 percent of our production at sales locations outside of Alberta. We used our transportation, storage and logistics assets and expertise to sell our products in higher-priced months, when the opportunities were available, which reduced the impact of the drop in crude oil prices on our realized sales prices.

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Our realized crude oil sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate decreases relative to the price of blended crude oil, our realized bitumen sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets and deliver it to the Edmonton hub. As such, our average cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and transportation to field locations. In addition, up to three months may elapse from when we purchase condensate to when we sell our blended production. In a declining crude oil price environment, we expect to see a negative impact on our realized bitumen sales price as we are using condensate purchased at a higher price earlier in the year. During the year we reduced condensate volumes transported from the USGC, as the price differential between market hubs was not significant enough to cover variable transportation costs for part of the year. Condensate prices declined during the summer months due to lower demand making it more cost-effective to buy in Alberta compared with the USGC.

As a result of our decisions to store rather than sell, we were able to minimize the impact on our realized sales prices. Cenovus uses its marketing and transportation initiatives, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification, to inventory physical positions. At the time we make the decision to store crude oil and condensate volumes, the prices available for future periods we plan to sell in can be locked in and the improved margin realized in the future periods, which are superior to short-term prices. The additional revenues generated from the underlying physical sales may be impacted by the related risk management gains and losses.

Transactions typically span across periods in order to execute the optimization strategy and these transactions reside across both realized and unrealized risk management. As the financial contracts settle, they will flow from unrealized to realized risk management gains and losses and final settlement will match when the physical product is sold.

Production Volumes

(barrels per day)	**2020**	**Percent Change**	2019	Percent Change	2018
Foster Creek	**163,210**	**2**	159,598	(1)	161,979
Christina Lake	**218,513**	**12**	194,659	(3)	201,017
	381,723	**8**	354,257	(2)	362,996

In 2020, we actively managed production levels to respond to price signals and the availability of production curtailment credits, both our own and those available in the market. In 2019, our production was in line with Government of Alberta's mandatory production curtailment program.

Royalties

Royalty calculations for our oil sands projects are based on government prescribed pre- and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price.

Royalties for a pre-payout project are based on a monthly calculation that applies a royalty rate (ranging from one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Royalties for a post-payout project are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 percent to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). For royalty purposes, gross revenues are a function of sales revenues less diluent costs and transportation costs and net profits are a function of sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

Foster Creek and Christina Lake are post-payout projects for determining royalties.

Effective Royalty Rates

(percent)	**2020**	2019	2018
Foster Creek	**7.9**	18.8	18.0
Christina Lake	**14.4**	21.6	4.8

In 2020, royalties decreased $819 million compared with 2019 as a result of lower net profits due to lower commodity pricing, combined with lower Alberta Department of Energy posted royalty rates related to decreased annual average WTI benchmark pricing.

Expenses

Transportation and Blending

Total transportation and blending costs have decreased $753 million compared with 2019. Blending costs decreased due to a decline in condensate price, partially offset by increased condensate volumes required to move increased bitumen volumes.

Transportation costs increased primarily due to higher fixed costs in 2020, as our rail freight and offloading commitments gradually increased in 2019 as the crude-by-rail program ramped up.

Per-unit Transportation Expenses

Foster Creek per-barrel transportation costs decreased $0.65 per barrel due to lower pipeline tariffs as a result of lower sales at U.S. destinations and increased sales volumes, partially offset by increased rail transportation costs from higher fixed costs in 2020, as discussed above. Christina Lake per-barrel transportation costs increased $0.31 per barrel as a result of increased pipelines tariff rates due to higher piped sales at U.S. destinations, higher fixed costs, as discussed above, and higher storage costs, partially offset by increased sales volumes relative to 2019.

Operating

Total operating costs increased $55 million due to higher fuel, workforce, and chemical costs from increased production, partially offset by lower repairs and maintenance costs and fluid, waste handling and trucking costs from the 2020 planned turnaround compared with the planned turnaround at Christina Lake in the second quarter of 2019 and reduction in activity and resources due to COVID-19 safety measures.

Per-unit Operating Expenses

($/bbl)	**2020**	**Percent Change**	2019	Percent Change	2018 (1)
Foster Creek					
Fuel	**2.83**	**15**	2.47	16	2.13
Non-fuel	**6.41**	**(4)**	6.67	(2)	6.84
Total	**9.24**	**1**	9.14	2	8.97
Christina Lake					
Fuel	**2.18**	**6**	2.06	10	1.87
Non-fuel	**4.61**	**(13)**	5.27	11	4.73
Total	**6.79**	**(7)**	7.33	11	6.60
Total	**7.84**	**(4)**	8.15	7	7.65

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

At both Foster Creek and Christina Lake, per-barrel fuel costs increased due to higher natural gas prices and consumption, partially offset by higher sales volumes.

Per-barrel non-fuel operating expenses at Foster Creek decreased in 2020 primarily due to higher sales volumes and COVID-19 safety measures implemented in the second quarter resulting in less repairs and maintenance activity, partially offset by higher workforce costs.

Per-barrel non-fuel operating expenses at Christina Lake decreased in 2020 primarily due to higher sales volumes, and lower costs for the 2020 planned turnaround compared with costs for the planned turnaround in 2019, partially offset by higher workforce and chemical costs.

Netbacks (1)

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). Netbacks reflect our margin on a per-barrel of oil equivalent basis. Netback is defined as gross sales less royalties, transportation and blending and operating expenses divided by sales volumes. Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold. The sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the heavy oil to transport it to market. For a reconciliation of our Netbacks see the Advisory section of this MD&A.

	Foster Creek			Christina Lake		
($/bbl)	**2020 (2)**	2019	2018	**2020 (2)**	2019	2018
Sales Price	**30.80**	57.21	42.63	**27.04**	50.91	33.42
Royalties	**1.57**	8.44	6.25	**2.90**	9.42	1.37
Transportation and Blending	**11.05**	11.70	8.34	**6.95**	6.64	5.25
Operating Expenses	**9.24**	9.14	8.97	**6.79**	7.33	6.60
Netback Excluding Realized Risk Management	**8.94**	27.93	19.07	**10.40**	27.52	20.20
Realized Risk Management Gain (Loss)	**(1.83)**	(0.16)	(11.49)	**(1.93)**	(0.19)	(11.66)
Netback Including Realized Risk Management	**7.11**	27.77	7.58	**8.47**	27.33	8.54

(1) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.
(2) The netbacks do not reflect non-cash write-downs or reversals of product inventory.

Our average Netback, excluding realized risk management gains and losses, decreased in 2020 compared with 2019, primarily due to lower realized sales prices, partially offset by lower royalties, operating costs and transportation and blending costs, and higher sales volumes. The weakening of the Canadian dollar relative to the U.S. dollar compared with 2019 had a positive impact on our overall reported sales price of approximately $0.30 per barrel.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate accounts for expenditures incurred to date, together with estimated future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A each period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves.

In 2020, DD&A increased $141 million compared with 2019, due to higher sales volumes, partially offset by a decrease in our average depletion rates. Our depletion rate decreased due to lower future development costs and a decrease in maintenance capital. The average depletion rate for the year ended December 31, 2020 was approximately $10.40 per barrel (2019 – $11.15 per barrel).

We depreciate our right-of-use ("ROU") assets on a straight-line basis over the shorter of the estimated useful life or the lease term.

Capital Investment

($ millions)	**2020**	2019	2018 (1)
Foster Creek	**193**	243	379
Christina Lake	**162**	362	445
	355	605	824
Other (2)	**72**	51	46
Capital Investment (3)	**427**	656	870

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(2) Includes Narrows Lake and new resource plays. In Q1 2020, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment. The comparative information has been reclassified.
(3) Includes expenditures on PP&E and E&E assets.

In 2020, Oil Sands capital investment focused on sustaining programs related to existing production at Foster Creek and Christina Lake as well as the stratigraphic test well program. Other capital investment related to advancing key initiatives and technology development costs. In 2019, capital investment primarily related to sustaining and stratigraphic test well programs and the completion of Christina Lake phase G construction.

Drilling Activity

	Gross Stratigraphic Test Wells			Gross Production Wells (1)		
	2020	2019	2018	**2020**	2019	2018
Foster Creek	**38**	14	43	**-**	-	14
Christina Lake	**42**	18	63	**-**	11	38
	80	32	106	**-**	11	52
Other (2)	**75**	26	20	**-**	-	-
	155	58	126	**-**	11	52

(1) Steam-assisted gravity drainage ("SAGD") well pairs are counted as a single producing well.

(2) Includes Narrows Lake and new resource plays. In Q1 2020, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment. The comparative information has been reclassified.

Stratigraphic test wells were drilled to help identify well pad locations for sustaining wells and future expansion phases, and to further progress the evaluation of emerging assets. In 2020, we increased the number of gross stratigraphic test wells drilled by increasing the scope of the program and incorporating more multi-leg wells, which have a reduced surface impact.

CONVENTIONAL

In 2020, we:

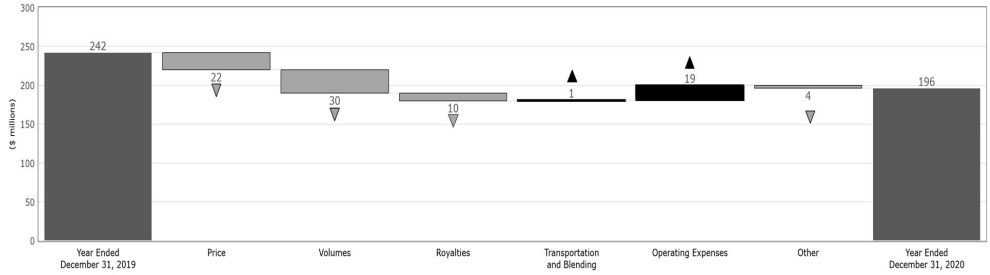
- Produced a total of 89,932 BOE per day, down from 2019 due to natural declines partially offset by added production from the Marten Hills area, prior to its divestiture on December 2, 2020;
- Generated Operating Margin of $196 million, a decrease from 2019 due to reduced sales volumes, lower realized prices, and higher royalties, partially offset by lower operating costs;
- Reduced operating costs by approximately six percent to $318 million compared with $337 million in 2019, by optimizing operations, focusing on critical repairs and maintenance activities and leveraging our infrastructure;
- Earned a Netback of $5.16 per BOE; and
- Divested our Marten Hills assets and entered into a Gross Overriding Royalty agreement and an equity position in the purchaser to benefit from its future development.

Financial Results

($ millions)	**2020**	2019	2018 (1)
Gross Sales	**635**	691	904
Less: Royalties	**40**	30	73
Revenues	**595**	661	831
Expenses			
Transportation and Blending	**81**	82	90
Operating	**318**	337	403
(Gain) Loss on Risk Management	**-**	-	26
Operating Margin	**196**	242	312
Depreciation, Depletion and Amortization	**880**	319	412
Exploration Expense	**82**	64	2,117
Segment Income (Loss)	**(766)**	(141)	(2,217)

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Operating Margin Variance



Revenues

Price

	2020	2019	2018
Heavy Oil ($/bbl)	**31.45**	-	-
Light and Medium Oil ($/bbl)	**42.78**	65.70	66.71
NGLs ($/bbl)	**22.04**	26.36	38.56
Natural Gas ($/mcf)	**2.37**	2.01	1.72
Total Oil Equivalent ($/BOE)	**17.84**	17.95	19.31

For the year ended December 31, 2020, revenues declined due to decreased average realized liquids sales prices and lower natural gas sales volumes, partially offset by higher natural gas sales prices and liquids sales volumes. In 2020, prior to its divestiture, we had heavy oil production from Marten Hills of approximately 2,700 barrels per day. In 2020, revenues included $49 million of processing fee revenue related to our interests in natural gas processing facilities (2019 – $53 million). We do not include processing fee revenue in our per-unit pricing metrics or our Netbacks.

Production Volumes

	2020	2019	2018
Liquids			
Crude Oil (barrels per day)	**7,244**	4,911	5,916
NGLs (barrels per day)	**19,513**	21,762	26,538
	26,757	26,673	32,454
Natural Gas (MMcf per day)	**379**	424	527
Total Production (BOE/d)	**89,932**	97,423	120,258
Natural Gas Production (percentage of total)	**70**	73	73
Liquids Production (percentage of total)	**30**	27	27

Production in 2020 decreased due to natural declines, partially offset by Marten Hills heavy oil production, prior to its divestiture.

Royalties

The Conventional assets are subject to royalty regimes in both Alberta and British Columbia. In Alberta, royalties benefit from a number of different programs that reduce the royalty rate on crude oil and natural gas production. Natural gas wells in Alberta also benefit from the Gas Cost Allowance ("GCA"), which reduces royalties, to account for capital and direct operating costs incurred to process and transport the Crown's share of raw gas at producer-owned gas plants as well as transport the Crown's share of residue gas, NGLs or oil through producer-owned sales pipelines.

In 2020, our effective royalty rate was 7.9 percent (2019 – 5.1 percent). The higher royalty rate is due to a reduction in capital and operating expenses in 2019 resulting in a reduced GCA recovery.

Expenses

Transportation

Our transportation costs reflect charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. The majority of our Conventional production is sold into the Alberta market. Per-unit transportation costs averaged $2.46 per BOE (2019 – $2.31 per BOE), due to lower sales volumes and increased pipeline costs.

Operating

Total operating costs decreased to $318 million (2019 – $337 million) through continuing efforts to optimize our operations and workforce, focusing on critical repair and maintenance activities and leveraging our infrastructure to lower the cost structure.

Per-unit operating costs increased to an average of $8.99 per BOE (2019 – $8.79 per BOE) primarily due to lower sales volumes partially offset by lower workforce costs, decreased property tax and lease costs primarily for lower lease rentals and from regulatory cost relief, and lower repairs and maintenance as a result of lower activity and deferrals.

Netbacks

($/BOE)	**2020**	2019	2018 (1)
Sales Price	**17.84**	17.95	19.31
Royalties	**1.23**	0.83	1.67
Transportation and Blending	**2.46**	2.31	1.97
Operating Expenses	**8.99**	8.79	8.58
Netback Excluding Realized Risk Management	**5.16**	6.02	7.09
Realized Risk Management Gain (Loss)	**(0.01)**	(0.01)	(0.59)
Netback Including Realized Risk Management	**5.15**	6.01	6.50

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

DD&A and Exploration Expense

We deplete crude oil and natural gas properties on a unit-of-production basis over proved reserves. The unit-of-production rate accounts for expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves. The average depletion rate was approximately $9.85 per BOE for the year ended December 31, 2020 (2019 – $9.15 per BOE).

For the year ended December 31, 2020, total Conventional DD&A was $880 million (2019 – $319 million). The increase was due to impairment charges of $555 million, as a result of the decline in forward crude oil and natural gas prices and a change in our future development plans, and higher DD&A rates.

Exploration expense of $82 million was recorded for the year ended December 31, 2020 (2019 – $64 million) as the carrying value of certain E&E assets were not considered to be recoverable.

Divestiture

On December 2, 2020, we sold our Marten Hills assets in northern Alberta to Headwater Exploration Inc. (“Headwater”) for total consideration of $138 million, excluding the retained gross overriding royalty interest (“GORR”). A before-tax gain of $79 million was recorded on the sale (after-tax – $65 million). Total consideration received consists of $33 million cash, 50 million common shares valued at $97 million and 15 million share purchase warrants valued at $8 million at the date of close. The share purchase warrants have a three-year term and an exercise price of $2.00 per share. We retained a GORR in the Marten Hills assets which was reclassified from E&E to PP&E for $41 million at the date of close. The investment in Headwater is held in other assets.

Capital Investment

In 2020, we invested $78 million compared with $103 million in 2019. Capital investment focused on the disciplined development of our Conventional assets, which encompassed maintaining safe and reliable operations, acquiring seismic data, start-up of a recompletion program to optimize existing production and commencement of a drilling program targeting low-risk, high-return development.

($ millions)	**2020**	2019 (1)	2018 (1)
Seismic	**5**	-	-
Drilling and Completions	**27**	32	123
Facilities	**20**	34	58
Other	**26**	37	47
Capital Investment (2)	**78**	103	228

(1) In Q1 2020, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment. The comparative information has been reclassified.
(2) Includes expenditures on PP&E and E&E assets.

Drilling Activity

In 2020 there were six net wells drilled, one net well completed and three net wells were tied-in and brought on production. In 2019, there were 11 net wells drilled, two net wells completed and three net wells tied-in.

REFINING AND MARKETING

In 2020, we:

- Managed to economic crude oil runs of 372,000 barrels per day, lower than 2019 in response to the economic slowdown due to COVID-19;
- Reported Operating Margin of negative $388 million, a decrease of $1,125 million compared with 2019, due to lower global crude oil and refined product pricing, which led to decreased market crack spreads and lower crude advantage, and decreased crude oil runs, partially offset by lower operating costs;
- Recorded an impairment charge of $450 million, as additional DD&A expense, associated with the Borger cash-generating unit ("CGU"); and
- Completed the temporary ramp down of our crude-by-rail program in the second quarter until pricing fundamentals supported its continuation in the fourth quarter.

Financial Results

($ millions)	2020	2019 (1)	2018 (1) (2)
Revenues	**6,051**	10,513	11,183
Purchased Product	**5,397**	8,795	9,201
Inventory Write-Down (Reversal)	**239**	49	60
Gross Margin	**415**	1,669	1,922
Expenses			
Operating	**824**	948	927
(Gain) Loss on Risk Management	**(21)**	(16)	(1)
Operating Margin	**(388)**	737	996
Depreciation, Depletion and Amortization	**739**	280	222
Segment Income (Loss)	**(1,127)**	457	774

(1) The comparative period has been reclassified to conform with current period treatment of non-cash inventory write-downs and reversals.
(2) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Refinery Operations (1)

	2020	2019	2018
Crude Oil Capacity (Mbbls/d)	**495**	482	460
Crude Oil Runs (Mbbls/d)	**372**	443	446
Heavy Crude Oil	**149**	177	191
Light/Medium	**223**	266	255
Refined Products (Mbbls/d)	**385**	466	470
Gasoline	**195**	223	233
Distillate	**127**	167	156
Other	**63**	76	81
Crude Utilization (percent)	**75**	92	97

(1) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.

On a 100 percent basis, the Refineries had total processing capacity re-rated on January 1, 2020 to 495,000 gross barrels per day of crude oil. The ability to process a wide slate of crude oils allows the Refineries to economically integrate heavy crude oil production. Processing less expensive crude oil relative to WTI creates a feedstock cost advantage, illustrated by the discount of WCS relative to WTI. The amount of heavy crude oil processed, such as WCS and Christina Dilbit Blend, is dependent on the quality and quantity of available crude oil with the total input slate optimized at each refinery to maximize economic benefit. Crude utilization represents the percentage of total crude oil processed in the Refineries relative to the total capacity.

Crude oil runs and refined product output decreased in 2020 compared with 2019 as both Refineries implemented crude rate reductions in response to the reduced demand due to COVID-19. In 2019, operational performance was impacted by unplanned outages, planned maintenance and turnaround activities at both Refineries.

Crude-By-Rail Terminal

Our crude-by-rail program was suspended in the first quarter in response to the low price market environment. The suspension was completed during the second quarter and lifted in the fourth quarter as market conditions improved. In 2020, we loaded an average of 32,213 barrels per day (22,891 barrels per day of our volumes) from our Bruderheim crude-by-rail terminal compared with an average of 65,293 barrels per day (45,324 barrels per day of our volumes) in 2019.

Gross Margin

While market crack spreads are an indicator of margin from processing crude oil into refined products, the refining realized crack spread, which is the gross margin on a per-barrel basis, is affected by many factors, such as the variety of feedstock crude oil processed; refinery configuration and the proportion of gasoline, distillate and

secondary product output; the time lag between the purchase of crude oil feedstock and the processing of that crude oil through the Refineries; and the cost of feedstock. Our feedstock costs are valued on a FIFO accounting basis.

In 2020, Refining and Marketing gross margin decreased $1,254 million resulting from decreased market crack spreads and crude advantage due to lower global crude oil and refined product pricing, and reduced crude oil runs.

In the year ended December 31, 2020, the cost of Renewable Identification Numbers ("RINs") was $177 million (2019 – $99 million). RIN costs increased, primarily due to higher pricing, partially offset by lower volume obligations. In 2020, RINs prices have been volatile and have steadily increased as RIN generation declined year over year, and at the same time RIN demand increased following a federal court decision to reduce the number of small refiners eligible for hardship exemptions.

Operating Expense

Primary drivers of operating expenses in 2020 were labour, maintenance, and utilities. Operating expenses decreased primarily due to lower maintenance activity compared with 2019 and lower utility costs.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 60 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. Refining and Marketing DD&A was $739 million compared with $280 million in 2019. The increase in DD&A is primarily due to an impairment charge of $450 million related to the Borger CGU.

Capital Investment

($ millions)	**2020**	2019	2018 (1)
Wood River Refinery	**158**	128	119
Borger Refinery	**85**	100	85
Marketing	**33**	52	4
Capital Investment	**276**	280	208

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Capital expenditures in 2020 focused primarily on yield enhancement, reliability and maintenance projects, as well as storage infrastructure projects.

CORPORATE AND ELIMINATIONS

In 2020, our risk management activities resulted in:

- Unrealized risk management losses of $56 million (2019 – $149 million) due to the realization of settled positions and changes in commodity prices compared with the prices at the end of the prior year; and
- Realized foreign exchange risk management losses of $5 million (2019 – gain of $1 million and loss of $1 million on interest rate swap contracts).

Transactions typically span across periods in order to execute the optimization strategy and these transactions reside across both realized and unrealized risk management.

Expenses

($ millions)	**2020**	2019	2018 (1)
General and Administrative (2)	**292**	331	1,020
Finance Costs	**536**	511	627
Interest Income	**(9)**	(12)	(19)
Foreign Exchange (Gain) Loss, Net	**(181)**	(404)	854
Transaction Costs	**29**	-	-
Re-measurement of Contingent Payment	**(80)**	164	50
(Gain) Loss on Divestiture of Assets	**(81)**	(2)	795
Other (Income) Loss, Net	**40**	9	13
	546	597	3,340

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(2) Onerous contract provisions of $629 million in 2018 have been reclassified to G&A.

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, employee long-term incentive costs and operating costs associated with our real estate portfolio. In 2020, G&A expenses were $39 million lower

primarily due to lower employee long-term incentive costs and operating costs associated with our real estate portfolio, partially offset by an onerous contract provision of $18 million.

Finance Costs

Finance costs increased by $25 million primarily due to a discount of $25 million on the repurchase of unsecured notes compared with $63 million in 2019.

The weighted average interest rate on outstanding debt for the year ended December 31, 2020 was 4.9 percent (2019 – 5.1 percent).

Foreign Exchange

($ millions)	**2020**	2019	2018
Unrealized Foreign Exchange (Gain) Loss	**(131)**	(827)	649
Realized Foreign Exchange (Gain) Loss	**(50)**	423	205
	(181)	(404)	854

In 2020, unrealized foreign exchange gains of $131 million were recorded primarily as a result of the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar as at December 31, 2020 was two percent stronger compared with December 31, 2019, resulting in unrealized gains.

Transaction Costs

Prior to December 31, 2020, we incurred transaction costs of $29 million for costs related to the Arrangement, excluding common share, preferred share and warrant issuance costs.

Re-measurement of Contingent Payment

Related to oil sands production, Cenovus has agreed to make quarterly payments to ConocoPhillips Company and certain of its subsidiaries (“ConocoPhillips”) during the five years subsequent to the closing date of the acquisition from ConocoPhillips of their 50 percent interest in the FCCL Partnership on May 17, 2017 (“the Conoco Acquisition”), for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. The quarterly payment is $6 million for each dollar that the WCS price exceeds $52 per barrel. There are no maximum payment terms. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment.

The contingent payment is accounted for as a financial option. The fair value of $63 million as at December 31, 2020 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the year ended December 31, 2020, a non-cash re-measurement gain of $80 million was recorded.

Average WCS forward pricing for the remaining term of the contingent payment is $42.93 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately $42.40 per barrel and $43.80 per barrel.

Other (Income) Loss, Net

For the year ended December 31, 2020, recorded a $100 million loss related to the Keystone XL pipeline project.

The Government of Canada passed the CEWS as part of its COVID-19 Economic Response Plan. The program is effective from March 15, 2020 to June 2021. For the year ended December 31, 2020, we recorded $40 million in other income from the CEWS program.

In 2020, we recognized $24 million of lease income (2019 - $17 million). Lease income is earned on tank subleases, operating leases related to our real estate ROU assets in which we are the lessor, and from the recovery of non-lease components for operating costs and unreserved parking related to our net investment in finance leases. Finance leases are included in other assets as net investment in finance leases.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements, office furniture, and certain ROU assets. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. DD&A in 2020 was $161 million (2019 – $107 million), of which $52 million of previously capitalized PP&E costs relating to information technology assets were written off due to synergies identified as a result of the Arrangement.

Income Tax

($ millions)	2020	2019	2018
Current Tax			
Canada	**(14)**	14	(128)
United States	**1**	3	2
Current Tax Expense (Recovery)	**(13)**	17	(126)
Deferred Tax Expense (Recovery)	**(838)**	(814)	(884)
Total Tax Expense (Recovery)	**(851)**	(797)	(1,010)

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions)	2020	2019	2018
Earnings (Loss) From Continuing Operations Before Income Tax	**(3,230)**	1,397	(3,926)
Canadian Statutory Rate (percent)	**24.0**	26.5	27.0
Expected Income Tax Expense (Recovery) From Continuing Operations	**(775)**	370	(1,060)
Effect of Taxes Resulting From:			
Statutory and Other Rate Differences	**19**	(52)	(57)
Non-Taxable Capital (Gains) Losses	**(42)**	(38)	89
Non-Recognition of Capital (Gains) Losses	**(42)**	(39)	87
Adjustments Arising from Prior Year Tax Filings	**(8)**	4	3
Alberta corporate rate reduction	**(7)**	(671)	-
Recognition of U.S. Tax Basis	**-**	(387)	(78)
Other	**4**	16	6
Total Tax Expense (Recovery) From Continuing Operations	**(851)**	(797)	(1,010)
Effective Tax Rate (percent)	**26.3**	(57.1)	25.7

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for income taxes is adequate. There are usually a number of tax matters under review and with consideration of the current economic environment, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

For the year ended December 31, 2020, a deferred tax recovery was recorded due to an impairment of the Borger CGU, Conventional CGUs and current period operating losses that will be carried forward, excluding unrealized foreign exchange gains and losses on long-term debt. In 2020, the Government of Alberta accelerated the reduction in the provincial corporate tax rate from 12 percent to eight percent.

In 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from12 percent to eight percent over four years. As a result, the Company recorded a deferred income tax recovery of $671 million for the year ended December 31, 2019. In addition, the Company recorded a deferred income tax recovery of $387 million due to an internal restructuring of the Company's U.S. operations resulting in a step-up in the tax basis of the Company's refining assets.

In 2018, the Company recorded a deferred tax recovery related to current period losses, including the write-down of the Conventional E&E assets and a $78 million recovery arising from an adjustment to the tax basis of the Company's refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in WRB Refining LP ("WRB"), which due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. The maximum recovery related to the carry back of losses to recover tax paid was reached in 2018.

Our effective tax rate is a function of the relationship between total tax expense (recovery) and the amount of earnings (loss) before income taxes. The effective tax rate differs from the statutory tax rate as it reflects different tax rates in other jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation, adjustments to the tax basis of the refining assets, variations in the estimate of reserves, differences between the provision and the actual amounts subsequently reported on the tax returns, and other permanent differences.

Capital Investment

Capital expenditures of $60 million for 2020 focused primarily on supporting investments in technology and infrastructure to modernize our workplace, improve our cost structure and reduce costs and risk.

DISCONTINUED OPERATIONS

On January 5, 2018, we completed the sale of the Suffield crude oil and natural gas operations in southern Alberta for cash proceeds of $512 million, before closing adjustments. After-tax earnings from discontinued operations for the year ended December 31, 2018 were $27 million. An after-tax gain on discontinuance of $220 million was recorded on the sale.

QUARTERLY RESULTS

Our results over the last four quarters were impacted by the volatility in commodity prices primarily due to the impacts of COVID-19 and OPEC and non-OPEC production output decisions. Light oil benchmark prices were low and volatile throughout the majority of 2020, compared with the price of WTI in 2019. WTI fell 19 percent to average US$46.17 per barrel in the first quarter compared with US$56.96 per barrel in the fourth quarter of 2019 and dropped further to average US$27.85 per barrel in the second quarter with a recovery to average US$42.66 per barrel in the fourth quarter. Average WTI and WCS benchmark prices decreased 25 percent and 19 percent, respectively in the fourth quarter of 2020 compared with 2019. As a result, our Operating Margin from continuing operations was $625 million in the fourth quarter of 2020, a decrease from $864 million in the fourth quarter of 2019. Net Loss was $153 million compared with Net Earnings of $113 million in 2019.

Selected Operating and Consolidated Financial Results

($ millions, except per share amounts)	2020				2019			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Commodity Prices								
Brent	**45.24**	43.37	33.27	50.96	62.50	62.00	68.34	63.88
WTI	**42.66**	40.93	27.85	46.17	56.96	56.45	59.83	54.90
WCS	**33.36**	31.84	16.38	25.64	41.13	44.21	49.18	42.53
Chicago Market Crack Spread	**7.05**	7.89	6.44	8.79	12.27	16.72	21.44	13.57
Production Volumes								
Liquids (barrels per day)	**405,280**	411,788	400,050	416,802	400,329	380,699	371,390	370,983
Natural Gas (MMcf per day)	**371**	360	392	395	403	407	432	458
Total Production (BOE per day)	**467,202**	471,799	465,415	482,594	467,448	448,496	443,318	447,270
Refinery Operations								
Crude Oil Runs (Mbbls/d)	**338**	382	325	442	456	465	474	375
Refined Products (Mbbls/d)	**350**	397	332	460	477	485	501	402
Revenues	**3,426**	3,659	2,174	3,968	4,838	4,736	5,603	5,004
Operating Margin (1)	**625**	594	291	(589)	864	1,080	1,277	1,239
Cash From (Used in) Operating Activities	**250**	732	(834)	125	740	834	1,275	436
Adjusted Funds Flow (2)	**341**	414	(462)	(146)	687	928	1,082	1,005
Operating Earnings (Loss)	**(551)**	(452)	(414)	(1,187)	(164)	284	267	69
Per Share **(3)** ($)	**(0.45)**	(0.37)	(0.34)	(0.97)	(0.13)	0.23	0.22	0.06
Net Earnings (Loss)	**(153)**	(194)	(235)	(1,797)	113	187	1,784	110
Per Share **(3)** ($)	**(0.12)**	(0.16)	(0.19)	(1.46)	0.09	0.15	1.45	0.09
Capital Investment (4)	**242**	148	147	304	317	294	248	317
Dividends								
Cash Dividends	**-**	-	-	77	77	60	62	61
Per Share ($)	**-**	-	-	0.0625	0.0625	0.0500	0.0500	0.0500

(1) Additional subtotal found in Note 1 of the Consolidated Financial Statements and interim Consolidated Financial Statements, and defined in this MD&A.
(2) Non-GAAP measure defined in this MD&A. The comparative periods have been reclassified to conform with the current period treatment of non-cash inventory write-downs and reversals.
(3) Represented on a basic and diluted per share basis.
(4) Includes expenditures on PP&E and E&E assets.

Fourth Quarter 2020 Results Compared With the Fourth Quarter 2019

Production Volumes

Total production in the fourth quarter of 2020 was in line with 2019. The fourth quarter reflects increased production levels in response to an improved pricing environment facilitated by the purchase of production curtailment credits and lifting of the mandatory curtailment level at the beginning of December 2020. This was partially offset by a planned turnaround and maintenance at Christina Lake and operational outages due to process

treatment upsets at Foster Creek. In the fourth quarter of 2019, production was limited due to mandatory production curtailments set by the Government of Alberta, offset by curtailment relief equivalent to incremental increases in rail shipments from the Special Production Allowance ("SPA").

In the fourth quarter of 2020, we sold 121,595 barrels per day, approximately 25 percent, of our Oil Sands production at sales locations outside of Alberta compared with 181,366 barrels per day, approximately 35 percent, in the fourth quarter of 2019.

Conventional production in the fourth quarter of 2020 decreased eight percent to 86,167 BOE per day mainly due to natural declines from lower sustaining capital investment. Production from the Marten Hills assets was approximately 2,000 barrels per day for the quarter.

Refining and Marketing Operations

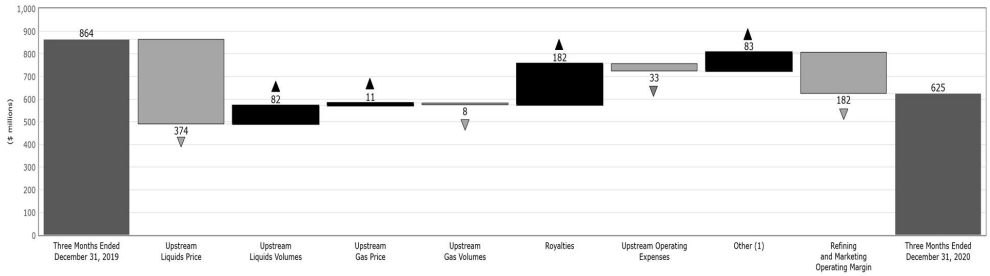
Crude oil runs of 338,000 gross barrels per day and refined product output of 350,000 gross barrels per day were lower compared with the same period in 2019 due to economic crude rate reductions in response to reduced demand as a result of COVID-19. In the fourth quarter of 2019 operations were impacted by planned turnaround activities and a crude supply constraint at Wood River as a result of a Keystone pipeline leak, partially offset by optimization of the total crude input slate.

In the fourth quarter of 2020, our crude-by-rail program was reinstated from the temporary suspension announced earlier in the year. Total rail volumes loaded at our Bruderheim crude-by-rail terminal averaged 29,144 barrels per day (20,423 barrels per day of our volumes) in the fourth quarter of 2020 compared with 89,630 barrels per day (71,708 barrels per day of our volumes) in the same period of 2019.

Revenues

Total revenues decreased $1,412 million in the fourth quarter of 2020 compared with the same period of 2019. Refining and Marketing revenues decreased $1,210 million primarily due to lower refined product pricing consistent with the declines in the average refined product benchmark prices and lower refined product output due to the economic crude rate reductions, and decreased revenues from third-party crude oil and natural gas sales undertaken by the marketing group. Upstream revenues decreased by $256 million primarily due to lower realized liquids sales pricing of $38.57 per barrel compared with $47.12 per barrel in 2019, partially offset by lower royalties and decreased sales volumes.

Operating Margin From Continuing Operations Variance



(1) Other includes the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Operating Margin

Operating Margin decreased in the fourth quarter of 2020 due to:

- A lower average liquids sales price as a result of decreased crude oil benchmark prices;
- Lower Operating Margin from our Refining and Marketing segment due to lower market crack spreads, decreased crude oil runs, lower crude advantage; and
- Increased upstream operating expenses.

These decreases were partially offset by lower royalties primarily due to our lower realized crude oil sales price and a decrease in our transportation and blending costs due to a decrease in rail transportation costs.

Cash From Operating Activities and Adjusted Funds Flow

Total Cash From Operating Activities and Adjusted Funds Flow decreased in the fourth quarter of 2020 compared with the same period in 2019, primarily due to lower Operating Margin, as discussed above, transaction costs of $29 million and changes in non-cash working capital. Adjusted Funds Flow was further reduced by a $100 million loss related to the Keystone XL pipeline project.

The change in non-cash working capital in the fourth quarter of 2020 was primarily due to an increase in accounts receivable and inventory, a decrease in income tax payable, and an increase in income tax receivable, partially offset by an increase in accounts payable. For 2019, the change in non-cash working capital was primarily due to an increase in accounts payable and a decrease in income tax receivable, partially offset by an increase in accounts receivable and inventory.

Operating Earnings (Loss)

Operating Loss increased in the three months ended December 31, 2020 compared with 2019 primarily due to higher DD&A due to $298 million in impairments and write-downs, lower Cash From Operating Activities and Adjusted Funds Flow, as discussed above, and higher non-cash employee long-term incentive costs mainly as a result of the accelerated vesting of our Employee Stock Option Plan, performance share units ("PSUs") and restricted share units ("RSUs") held by non-executive employees due to the closing of the Arrangement, partially offset by non-operating realized foreign exchange losses of $nil compared with $122 million in 2019.

Net Earnings (Loss)

Net Loss of $153 million increased for the three months ended December 31, 2020 compared with Net Earnings of $113 million in 2019. The change was primarily due to higher Operating Loss, as discussed above, partially offset by non-operating unrealized foreign exchange gains of $358 million compared with $258 million in 2019 and a deferred income tax recovery of $182 million compared with $24 million in 2019.

Capital Investment

Capital investment from continuing operations in the fourth quarter of 2020 was $242 million, $75 million lower compared with the fourth quarter of 2019, primarily due to the reduction of our capital investment program in response to COVID-19.

OIL AND GAS RESERVES

We retain IQREs to evaluate and prepare reports on 100 percent of our bitumen, heavy crude oil, light and medium oil, NGLs, conventional natural gas and shale gas proved and probable reserves.

Reserves

As at December 31, 2020 (before royalties)	**Bitumen** (MMbbls)	**Light and Medium Oil** (MMbbls)	**NGLs** (MMbbls)	**Conventional Natural Gas (1)** (Bcf)	**Total** (MMBOE)
Proved	**4,812**	**7**	**50**	**965**	**5,030**
Probable	**1,520**	**6**	**31**	**601**	**1,656**
Proved plus Probable	**6,332**	**13**	**81**	**1,566**	**6,686**

As at December 31, 2019 (before royalties)	**Bitumen (2)** (MMbbls)	**Light and Medium Oil** (MMbbls)	**NGLs** (MMbbls)	**Conventional Natural Gas (1)** (Bcf)	**Total** (MMBOE)
Proved	**4,826**	**9**	**60**	**1,242**	**5,103**
Probable	**1,594**	**8**	**37**	**783**	**1,768**
Proved plus Probable	**6,420**	**17**	**97**	**2,025**	**6,871**

(1) Includes shale gas reserves that are not material.
(2) Includes heavy crude oil reserves that are not material.

Developments in 2020 compared with 2019 include:

- Bitumen proved and proved plus probable reserves decreasing 14 million barrels and 88 million barrels, respectively, as additions from improved performance in Oil Sands were more than offset by the Marten Hills disposition and current year production;
- Light and medium oil proved and proved plus probable reserves decreasing two million barrels and four million barrels, respectively, as minor additions were more than offset by technical revisions attributed to updates to the Conventional development plan, reduced product pricing and current year production;
- NGLs proved and proved plus probable reserves decreasing 10 million barrels and 16 million barrels, respectively, as minor additions and a minor acquisition were more than offset by reductions due to technical revisions attributed to updates to the Conventional development plan, reduced product pricing and current year production; and
- Conventional natural gas proved and proved plus probable reserves decreasing 277 billion cubic feet and 459 billion cubic feet, respectively, as minor additions and a minor acquisition were more than offset by

reductions due to technical revisions attributed to updates to the Conventional development plan, reduced product pricing and current year production.

The reserves data is presented as at December 31, 2020 using an average of forecasts ("IQRE Average Forecast") by McDaniel & Associates Consultants Ltd. ("McDaniel"), GLJ Ltd. ("GLJ") and Sproule Associates Limited ("Sproule"). The IQRE Average Forecast prices and costs are dated January 1, 2021. Comparative information as at December 31, 2019 uses the January 1, 2020 IQRE Average Forecast prices and costs.

As a result of the close of the Arrangement on January 1, 2021, including reported reserves from Husky, our total proved reserves and total proved plus probable reserves are anticipated to increase by approximately 1.2 billion BOE and 1.8 billion BOE, respectively.

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") is contained in our AIF for the year ended December 31, 2020. Our AIF is available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com. Material risks and uncertainties associated with estimates of reserves are discussed in this MD&A in the Risk Management and Risk Factors section and the Advisory section in this MD&A.

Information concerning Husky and its reserves data and other oil and gas information as of December 31, 2020 may be found in the Husky AIF and the Husky MD&A, each of which is filed and available on SEDAR under Husky's profile at sedar.com.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	**2020**	2019	2018
Cash From (Used in)			
Operating Activities	**273**	3,285	2,154
Investing Activities	**(863)**	(1,432)	(613)
Net Cash Provided (Used) Before Financing Activities	**(590)**	1,853	1,541
Financing Activities	**837**	(2,413)	(1,410)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(55)**	(35)	40
Increase (Decrease) in Cash and Cash Equivalents	**192**	(595)	171

As at December 31,	**2020**	2019	2018
Cash and Cash Equivalents	**378**	186	781
Debt	**7,562**	6,699	9,164

As at December 31, 2020, we were in compliance with all of the terms of our debt agreements.

Cash From (Used in) Operating Activities

For the year ended December 31, 2020, cash generated by operating activities decreased mainly due to lower Operating Margin, transaction costs of $29 million, partially offset by funding from the CEWS program and sublease income, and lower current taxes, as discussed in the Corporate and Eliminations section of this MD&A, and changes in non-cash working capital, as discussed in the Operating and Financial Results section of this MD&A.

Excluding the current portion of the contingent payment, our working capital was $653 million at December 31, 2020 compared with $842 million at December 31, 2019.

We anticipate that we will continue to meet our payment obligations as they come due.

Cash From (Used in) Investing Activities

Cash used in investing activities was lower in 2020 compared with 2019 primarily due to decreased capital investment in 2020.

Cash From (Used in) Financing Activities

In the first quarter of 2020, we repurchased US$100 million of unsecured notes for cash of US$81 million. In the third quarter of 2020 we issued US$1.0 billion in 5.375 percent senior unsecured notes due in 2025 and used the proceeds to repay $1.4 billion of borrowings on our committed credit facility.

In 2019, cash was used in financing activities primarily for the repayment of debt. We repaid US$1.8 billion of unsecured notes for cash consideration of US$1.7 billion ($2.3 billion).

Total debt, including short-term borrowings, as at December 31, 2020 was $7,562 million (December 31, 2019 – $6,699 million).

Common Share Dividends

On April 2, 2020 we announced the temporary suspension of our common share dividend in response to the low global crude oil price environment. Prior to the suspension, we paid common share dividends of $77 million or 0.0625 per common share in the first quarter of 2020 (year ended December 31, 2019 – $260 million or $0.2125 per common share). The declaration of dividends is at the sole discretion of the Board and is considered quarterly. The Board declared a first quarter dividend of $0.0175 per common share, payable on March 31, 2021 to common shareholders of record as of March 15, 2021.

Cumulative Redeemable Preferred Share Dividend

The Board declared a first quarter dividend on the Series 1, 2, 3, 5, and 7 preferred shares, payable on March 31, 2021, in the amount of $8 million.

Available Sources of Liquidity

The following sources of liquidity are available at December 31, 2020:

($ millions)	Term	Amount Available
Cash and Cash Equivalents	**Not applicable**	**378**
Committed Credit Facilities		
Revolving Credit Facility – Tranche A	**November 2023**	**3,300**
Revolving Credit Facility – Tranche B	**November 2022**	**1,200**
Uncommitted Demand Facilities		
Cenovus Energy Inc.	**Not applicable**	**600**
WRB Refining LP (Cenovus's proportionate share)	**Not applicable**	**70**

In light of the current challenging economic conditions, we expect to fund our near-term cash requirements through cash from operating activities and prudent use of our balance sheet capacity including draws on our committed credit facilities and our uncommitted demand facilities and other corporate and financial opportunities that may be available to us.

Committed Credit Facilities

As at December 31, 2020, we had a total committed credit facility of $4.5 billion that consisted of a $1.2 billion tranche maturing on November 30, 2022 and a $3.3 billion tranche maturing November 30, 2023. During the second quarter, we added a committed credit facility with capacity of $1.1 billion, with a term of 364 days that was renewable for one year at our request and upon approval by the lenders, to further support our financial resilience. On December 31, 2020, we cancelled the $1.1 billion committed credit facility. As at December 31, 2020, no amount was drawn on the committed credit facility (December 31, 2019 - $265 million).

Uncommitted Demand Facilities

As at December 31, 2020, Cenovus had uncommitted demand facilities of $1.6 billion in place, of which $600 million may be drawn for general purposes or the full amount can be available to issue letters of credit. As at December 31, 2020, the Company had drawn no amounts (December 31, 2019 - $nil) on these facilities and there were outstanding letters of credit aggregating to $441 million (December 31, 2019 - $364 million).

WRB has uncommitted demand facilities of US$300 million (the Company's proportionate share - US$150 million) available to cover short-term working capital requirements. As at December 31, 2020, US$190 million was drawn on these facilities, of which US$95 million ($121 million) was the Company's proportionate share (December 31, 2019 – $nil).

Base Shelf Prospectus

Cenovus has in place a base shelf prospectus that allows us to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in October 2021. On July 30, 2020, we completed a public offering in the U.S., under the U.S. base shelf prospectus, of senior unsecured notes in the aggregate principal amount of US$1.0 billion due in 2025. As at December 31, 2020, US$3.7 billion remained available under the base shelf prospectus for permitted offerings.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted EBITDA and Net Debt to Capitalization. We define our non-GAAP measure of Net Debt as short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. We define Capitalization as Net Debt plus Shareholders' Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense (recovery), DD&A, E&E write-down, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent

payment, gains (losses) on divestiture of assets, and other income (loss), net, calculated on a trailing twelve-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

As at December 31,	**2020**	2019	2018
Net Debt to Capitalization (1) (percent)	**30**	25	32
Net Debt to Adjusted EBITDA (times)	**11.9x**	1.6x	5.8x

(1) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.

(2) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

A reconciliation of Adjusted EBITDA, and the calculation of Net Debt to Adjusted EBITDA can be found in Note 24 of the Consolidated Financial Statements.

Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times over the long-term. This ratio may periodically be above the target due to factors such as persistently low commodity prices. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure the Company has sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, draw down on our credit facilities or repay existing debt, adjust dividends paid to shareholders, repurchase our common shares for cancellation, issue new debt, or issue new shares.

As at December 31, 2020, Cenovus's Net Debt to Adjusted EBITDA was 11.9 times. Net Debt to Adjusted EBITDA increased compared with December 31, 2019 as a result of an increase in our borrowings, as mentioned in the Cash From (Used In) Financing Activities above, and a reduction in our trailing twelve-month adjusted EBITDA.

We also manage our Net Debt to Capitalization ratio to ensure compliance with the associated covenants as defined in our committed credit facility agreements. Under the terms of Cenovus's committed credit facility at the end of the year, we were required to maintain a debt to capitalization ratio, as defined in the agreement, not to exceed 65 percent. We were well below this limit at December 31, 2020.

Additional information regarding our financial measures and capital structure can be found in the notes to the Consolidated Financial Statements.

Share Capital and Stock-Based Compensation Plans

As at December 31, 2020, there were approximately 1,229 million common shares outstanding (2019 – 1,229 million common shares). Refer to Note 30 of the Consolidated Financial Statements for more details.

Refer to Note 32 of the Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and deferred share unit ("DSU") Plans.

Our outstanding share data is as follows:

As at January 31, 2021	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares (1)	**2,017,404**	**N/A**
Common Share Warrants	**65,418**	**N/A**
Preferred Shares Series 1	**10,436**	**N/A**
Preferred Shares Series 2	**1,564**	**N/A**
Preferred Shares Series 3	**10,000**	**N/A**
Preferred Shares Series 5	**8,000**	**N/A**
Preferred Shares Series 7	**6,000**	**N/A**
Stock Options (2)	**30,499**	**23,305**
Other Stock-Based Compensation Plans	**3,715**	**1,293**

(1) ConocoPhillips continued to hold 208 million common shares issued as partial consideration related to the Conoco Acquisition.

(2) Includes Cenovus Replacement Options (defined below) issued pursuant to the Arrangement in replacement of all issued and outstanding Husky stock options.

Capital Investment Decisions

Our approach on the financial framework of the combined company will be consistent with the parameters we have set for Cenovus in prior years. We will continue to evaluate all opportunities based on a US$45.00 per barrel WTI price with the objective of maintaining a prudent and flexible capital structure and strong balance sheet metrics. This approach positions us to be financially resilient in times of lower cash flows. Balance sheet strength continues to be a top priority and we plan to continue to direct our Free Funds Flow towards debt reduction. We continue to target a Net Debt to EBITDA ratio not to exceed two times.

Our 2021 capital program for the combined company is forecast to be between $2.3 billion and $2.7 billion. The budget is focused on maintaining safe and reliable operations while positioning the Company to drive enhanced shareholder value and includes sustaining capital of approximately $2.1 billion to deliver upstream production of approximately 755,000 BOE per day and downstream throughput of approximately 525,000 barrels per day.

($ millions)	2020	2019	2018
Adjusted Funds Flow (1)	**147**	3,702	1,721
Total Capital Investment	**841**	1,176	1,363
Free Funds Flow (1) (2)	**(694)**	2,526	358
Cash Dividends	**77**	260	245
	(771)	2,266	113

(1) The comparative period has been reclassified to conform with current period treatment of non-cash inventory write-downs and reversals.
(2) Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.

We remain committed to maintaining and improving our current investment-grade credit ratings. This includes our continued focus on allocating free funds flow to reduce Net Debt to less than $10 billion and targeting a longer-term Net Debt level at or below $8 billion.

The combined company's adjusted funds flow is expected to fully fund sustaining capital and shareholder distributions. The Board declared a first quarter dividend of $0.0175 per common share, payable on March 31, 2021, to common shareholders of record as of March 15, 2021. The Board declared a first quarter dividend on the Series 1, 2, 3, 5, and 7 preferred shares, payable on March 31, 2021, in the amount of $8 million.

Contractual Obligations and Commitments

Cenovus has obligations for goods and services entered into in the normal course of business. Obligations are primarily related to transportation agreements, our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. Obligations that have original maturities of less than one year are excluded. For further information, see the notes to Consolidated Financial Statements.

As at December 31, 2020, total commitments were $23 billion, of which $21 billion are for various transportation and storage commitments. Terms are up to 20 years subsequent to the date of commencement and should help align with the Company's future transportation requirements with anticipated production growth. Transportation and storage commitments include future commitments relating to storage tank leases of $31 million, that have not yet commenced.

	Expected Payment Date						
($ millions)	2021	2022	2023	2024	2025	Thereafter	**Total**
Commitments							
Transportation and Storage (1)	1,014	954	1,341	1,444	1,107	15,537	**21,397**
Real Estate (2)	34	36	38	41	44	604	**797**
Capital Commitments	1	2	-	-	-	-	**3**
Other Long-Term Commitments	104	45	32	32	24	85	**322**
Total Commitments (3)	1,153	1,037	1,411	1,517	1,175	16,226	**22,519**
Other Obligations							
Long-term Debt (Principal and Interest)	385	1,024	941	346	1,620	8,627	**12,943**
Decommissioning Liabilities	41	45	41	42	41	2,429	**2,639**
Contingent Payment	36	28	-	-	-	-	**64**
Lease Liabilities (Principal and Interest) (4)	254	237	208	203	162	1,412	**2,476**
Total Commitments and Obligations	1,869	2,371	2,601	2,108	2,998	28,694	**40,641**

(1) Includes transportation commitments of $14 billion (December 31, 2019 – $13 billion) that are subject to regulatory approval or have been approved but are not yet in service.
(2) Relates to the non-lease components of lease liabilities consisting of operating costs and unreserved parking for office space. Excludes committed payments for which a provision has been provided.
(3) Contracts undertaken on behalf of WRB are reflected at our 50 percent interest.
(4) Lease contracts related to office space, railcars, storage assets, drilling rigs and other refining and field equipment.

We continue to focus on mid-term strategies to broaden market access for our crude oil production. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving our crude oil production to market by rail, and assessing options to maximize the value of our crude oil.

As at December 31, 2020, there were outstanding letters of credit aggregating $441 million issued as security for performance under certain contracts (December 31, 2019 – $364 million).

Liquidity and Capital Resources Subsequent to the Arrangement

Share Capital and Stock-Based Compensation

At the closing of the Arrangement on January 1, 2021, we acquired all of the issued and outstanding Husky common shares in consideration for the issuance of 0.7845 Cenovus common shares and 0.0651 Cenovus warrants ("Cenovus Warrants") for each Husky common share. All the issued and outstanding Husky preferred shares were exchanged for Cenovus preferred shares with substantially identical terms, and all issued and outstanding Husky stock options were exchanged for Cenovus replacement stock options ("Cenovus Replacement Options"). Each Cenovus Replacement Option entitles the holder to acquire 0.7845 of a Cenovus common share at an exercise price per share of a Husky stock option divided by 0.7845. Refer to Notes 30 and 39 of the Consolidated Financial Statements for more details.

The Arrangement resulted in the accelerated vesting of certain stock-based compensation plans of the Company. Refer to Notes 32 and 39 of the Consolidated Financial Statements for more details. In accordance with their terms, the PSUs and RSUs may be settled, at the discretion of Cenovus, in Cenovus common shares, cash, or a combination of both based on the 30-day volume weighted average trading price prior to the date of closing. The obligations associated all PSUs and RSUs that were settled in connection with the completion of the Arrangement were paid in cash in January 2021.

In connection with the Arrangement, a DSU holder that ceased to be a Cenovus director or employee will be entitled to the settlement and redemption of their DSUs, in cash based on the five day volume weighted average trading prior to the date of redemption, in accordance with the terms of the related DSU Plan.

Liquidity and Commitments

At closing of the Arrangement on January 1, 2021, Cenovus obtained access to additional sources of capital including: $735 million in cash and cash equivalents, $3.7 billion available on Husky's committed credit facilities and $508 million available on Husky's uncommitted demand facilities. Husky's committed credit facilities have a capacity of $4.0 billion and its uncommitted demand facilities have a capacity of $975 million, of which $850 million may be drawn for general purposes, or the full amount can be available to issue letters of credit.

We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, Moody's Investor Service ("Moody's") and DBRS Limited and re-establishing investment grade ratings at Fitch Ratings ("Fitch"). The cost and availability of borrowing, and access to sources of liquidity and capital is dependent on current credit ratings as determined by independent rating agencies and market conditions.

The Arrangement resulted in the assumption of Husky's known non-cancellable contracts and other commercial commitments. On January 1, 2021, total commitments assumed by Cenovus were $19 billion, of which $2 billion were for various transportation commitments that are subject to regulatory approval or have been approved, but are not yet in service.

Additional information concerning Husky's liquidity and commitments as of December 31, 2020 may be found under the sections Sources of Liquidity and Contractual Obligations, Commitments and Off-Balance Sheet Arrangements in the Husky MD&A, which is filed and available on SEDAR under Husky's profile at sedar.com.

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. We believe that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on our Consolidated Financial Statements.

Contingent Payment

In connection with the Conoco Acquisition and related to our Oil Sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. As at December 31, 2020, the estimated fair value of the contingent payment was $63 million. As at December 31, 2020, no amount was payable under the agreement. See the Corporate and Eliminations section of this MD&A for more details.

RISK MANAGEMENT AND RISK FACTORS

We are exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the energy industry as a whole and others are unique to our operations. The impact of any risk or a combination of risks may adversely affect, among other things, Cenovus's business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict our ability to pursue our strategic priorities, respond to changes in our operating environment, pay dividends to our shareholders and fulfill our obligations (including debt servicing requirements) and may materially affect the market price of our securities.

Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of Cenovus's risk and is integrated with our Operations Management Systems. In addition, we continuously monitor our risk profile as well as industry best practices.

Risk Governance

The *ERM Policy*, approved by our Board, outlines our risk management principles and expectations, as well as the roles and responsibilities of all staff. Building on the *ERM Policy*, we have established risk management standards, a risk management framework and risk assessment tools, including risk matrices. Our risk management framework contains the key attributes recommended by the International Organization for Standardization ("ISO") in its ISO 31000 – Risk Management Guidelines. The results of our ERM program are documented in an Annual Risk Report presented to the Board as well as through regular updates.

Risk Factors

The following discussion describes the financial, operational, regulatory, environmental, reputational and other risks related to Cenovus. Each risk identified in this MD&A may individually, or in combination with other risks, have a material impact on our business, financial condition, results of operations, cash flows, or reputation and should be considered when purchasing securities of Cenovus.

Pandemic Risk

The COVID-19 pandemic and measures taken in response by governments and health authorities around the world have resulted in a significant slow-down in global economic activity that has reduced the demand for, and adversely affected the prices of, commodities that are closely linked to Cenovus's financial performance, including crude oil, refined products (such as jet fuel, diesel and gasoline), natural gas and electricity, and also increases the risk that storage for crude oil and refined products could reach capacity in certain geographic locations in which Cenovus operates variant strains of COVID-19 have been identified. While some economies have started to re-open and vaccines have been developed, resurgences in cases of COVID-19 have occurred in certain locations and the risk of additional resurgences in other locations remains high. This creates ongoing uncertainty that has resulted in and could result in further restrictions on movement and businesses being re-imposed or imposed on a stricter basis, which could negatively impact demand for commodities and commodity prices and negatively impact our business, results of operations and financial condition. It is impossible at this point to predict precisely the duration or extent of the impacts of the COVID-19 pandemic on Cenovus's employees, customers, partners and business or when economic activity will normalize.

The COVID-19 pandemic may increase our exposure to, and magnitude of, each of the risks identified in the Risk Management and Risk Factors section of this MD&A. Our business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, ability to fund dividend payments and/or business plans may, in particular, without limitation, be adversely impacted as a result of the pandemic and/or decline in commodity prices as a result of:

- The shut-down of facilities or the delay or suspension of work on major capital projects due to workforce disruptions or labour shortages caused by workers becoming infected with COVID-19, or government or health authority mandated restrictions on travel by workers or closure of facilities, workforce camps or worksites;
- Disruptions to global supply chains, such as suppliers and third-party vendors experiencing similar workforce disruptions or being ordered to cease operations;
- Reduced cash flows resulting in less funds from operations being available to fund our capital expenditure budget;
- Reduced commodity prices resulting in a reduction in the volumes and value of our reserves. See "Commodity Prices" below;
- Commodity storage constraints resulting in the curtailment or shutting in of production;
- A decrease in refined product volumes, the demand for refined products, or refinery utilization rates;
- Counterparties being unable to fulfill their contractual obligations to us on a timely basis or at all;
- The inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate;
- The capabilities of our information technology systems and the potential heightened threat of a cyber-security breach arising from the number of employees, customers, and partners working remotely; and
- Our ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

The extent to which COVID-19 impacts our business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict, including, but not limited to, the severity, duration, spread or resurgence of COVID-19 or any variants thereof; the timing, extent and effectiveness of actions taken to contain or treat COVID-19 or its variants, including the availability, distribution rate and effectiveness of any vaccines; and the speed and extent to which normal economic and operating conditions resume. The potential impacts of COVID-19 to our business, results of operations and financial condition could be more significant in the current year as compared with 2020. Even after the COVID-19 pandemic has subsided, we may continue to experience materially adverse impacts to our business as a result of the pandemic's global economic impact.

There are no comparable recent events that provide guidance as to the effect the spread of COVID-19 as a global pandemic may have, and, as a result, the ultimate impact of the outbreak is highly uncertain and subject to change. Management does not yet know the full extent of the impacts on our business and operations or the global economy as a whole.

We have taken proactive steps to protect the health and safety of our staff and the continuity of our business in response to the COVID-19 pandemic. We continue to follow guidance received from the Federal, Provincial and state governments and public health officials. We also have a comprehensive Business Continuity Plan to ensure continued safe and reliable operations in the event of a COVID-19 outbreak at any of our workplaces. Despite our best efforts, the COVID-19 pandemic may result in new legal disputes, including class action claims.

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. Financial risks include, but are not limited to: fluctuations in commodity prices, development or operating costs; risks related to Cenovus's hedging activities; exposure to counterparties; availability of capital and access to sufficient liquidity; risks related to Cenovus's credit ratings; and fluctuations in foreign exchange and interest rates. In addition, we identify risks related to our ability to pay a dividend to shareholders; and risks related to internal control over financial reporting ("ICFR"). Changes in financial management and/or market conditions could impact a number of factors including, but not limited to, Cenovus's cash flows, Cenovus's ability to maintain desirable ratios of debt (and Net Debt) to Adjusted EBITDA as well as debt (and Net Debt) to capitalization, Cenovus's financial condition, results of operations and growth, the maintenance of our existing operations and business plans, financial strength of our counterparties, access to capital and cost of borrowing.

Excess Crude Oil Supply Risk

It is not known how long low commodity price conditions will continue, however if the situation continues, worsens or is exacerbated further by the impact of COVID-19, and global crude oil prices remain low for a prolonged period, our production, project development, profitability, cash flows, ability to access additional capital, and securities trading price, among other things, could be adversely impacted. While OPEC members agreed to certain production cuts through April 2022 and have reconfirmed their commitment to a stable oil market amid the global demand reduction caused by the pandemic, the stated reductions have since been varied and there can be no assurances that OPEC members and other oil exporting nations will abide by the agreed reductions or continue to agree to actions to stabilize oil prices. Uncertainty regarding the future actions of such nations may lead to increased commodity price volatility. See "Commodity Prices" below.

Commodity Prices

Our financial performance is significantly dependent on the prevailing prices of crude oil, refined products, natural gas and NGLs. Crude oil prices are impacted by a number of factors including, but not limited to: global and regional supply of and demand for crude oil; global economic conditions including factors impacting global trade; the actions of OPEC and other oil exporting nations including, without limitation, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC not to impose production quotas on its members; actions by the Government of Alberta including, without limitation, imposing, amending, or lifting crude oil production curtailments or SPA for crude-by-rail, and compliance or non-compliance with imposed crude oil production curtailments or SPA for crude-by-rail; enforcement of government or environmental regulations; public sentiment towards the use of non-renewable resources, including crude oil; political stability and social conditions in oil producing countries, market access constraints and transportation interruptions (pipeline, marine or rail); prices and availability of alternate fuel sources; outbreak of war; outbreak or continuation of a pandemic; terrorist threats; technological developments; the occurrence of natural disasters; and weather conditions.

Cenovus's natural gas and NGL production is currently located in Western Canada and Asia Pacific. Western Canadian natural gas prices are impacted by a number of factors including, but not limited to: North American supply and demand; developments related to the market for liquefied natural gas; prices and availability of alternate sources of energy; government or environmental regulations; public sentiment towards the use of non-renewable resources, including natural gas and NGLs; market access constraints and transportation interruptions; economic conditions; technological developments; the occurrence of natural disasters; and weather conditions.

Refined product prices are impacted by a number of factors including, but not limited to: global and regional supply and demand for refined products; market competitiveness; levels of refined product inventories; refinery availability; planned and unplanned refinery maintenance; current and potential future environmental regulations pertaining to the production and use of refined products; prices and availability of alternate sources of energy; public sentiment towards the use of refined products; prices and the availability of alternate fuel sources; technological developments; the occurrence of natural disasters; and weather conditions. In addition, and relating to the level of future demand (and corresponding price levels) for each of crude oil, refined products and natural gas, there has been a significant increase in focus recently on the timing for and pace of the transition to a lower-carbon economy. See "Climate Change Transition – Demand and Commodity Prices" below. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance is also impacted by discounted or reduced commodity prices for our oil sands production relative to certain international benchmark prices, due, in part, to constraints on the ability to transport and sell products to domestic or international markets and the quality of oil produced. Of particular importance to us are diluent cost and supply and the price differentials between bitumen and both light to medium crude oil and heavy crude oil. Bitumen is more expensive for refineries to process and therefore generally trades at a discount to the market price for light and medium crude oil and heavy crude oil.

The financial performance of our refining operations is impacted by the relationship, or margin, between refined product prices and the prices of refinery feedstock. Refining margins are subject to seasonal factors as production changes to match seasonal demand. Sales volumes, prices, inventory levels and inventory values will fluctuate

accordingly. Future refining margins are uncertain and decreases in refining margins may have a negative impact on our business.

Fluctuations in the price of commodities, associated price differentials and refining margins may impact our ability to meet guidance targets, the value of our assets, our cash flows and our ability to maintain our business and fund projects. A substantial decline in these commodity prices or extended period of low commodity prices may result in an inability to meet all of our financial obligations as they come due, a delay or cancellation of existing or future drilling, development or construction programs, curtailment in production (independent of any crude oil production curtailment mandated by the Government of Alberta then in effect), unutilized long-term transportation commitments and/or low utilization levels at Cenovus's refineries. Fluctuations in commodity prices, associated price differentials and refining margins impact our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

The commodity price risks noted above, as well as other risks such as market access constraints and transportation restrictions, reserves replacement and reserves estimates, and cost management that are more fully described herein, and may have a material impact on our business, financial condition, results of operations, cash flows or reputation, may be considered to be indicators of impairment. Another indication of impairment is the comparison of the carrying value of our assets to our market capitalization.

As discussed in this MD&A, we conduct an assessment, at each reporting date, of the carrying value of our assets in accordance with IFRS. If crude oil, refined product and natural gas prices decline significantly and remain at low levels for an extended period of time, or if the costs of our development of such resources significantly increases, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts, market access commitments and generally through our access to committed credit facilities. In certain instances, Cenovus will use derivative instruments to manage exposure to price volatility on a portion of its refined product, oil and gas production, inventory or volumes in long-distance transit. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 35 and 36 of the Consolidated Financial Statements and "Hedging Activities" below.

Additionally, the factors discussed under the headings "Pandemic Risk" and "Excess Crude Oil Supply Risk" could continue to negatively impact commodity prices. If crude oil, refined product and natural gas prices remain at low levels for an extended period, or if the costs of development of our resources significantly increases, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected.

Development and Operating Costs

Our financial outlook and performance is significantly affected by the cost of developing, sustaining and operating our assets. Development and operating costs are affected by a number of factors including, but not limited to: development, adoption and success of new technologies; inflationary price pressure; changes in regulatory compliance costs; scheduling delays; failure to maintain quality construction and manufacturing standards; and supply chain disruptions, including access to skilled labour. Electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating costs that are susceptible to significant fluctuation.

Hedging Activities

Cenovus's *Market Risk Management Policy*, which has been approved by the Board, allows Management to use derivative instruments including exchange-traded future contracts, commodity put and call options and other approved instruments as needed to help mitigate the impact of changes in crude oil and natural gas prices, crude oil differentials, diluent or condensate supply prices and differentials, refined product and crack spread margins, as well as fluctuations in foreign exchange rates and interest rates. Cenovus may also use firm commitments for the purchase or sale of crude oil, natural gas and refined products. Cenovus also uses derivative instruments in various operational markets to help optimize our supply costs or sales of our production.

The use of such hedging activities exposes us to risks which may cause significant loss. These risks include, but are not limited to: changes in the valuation of the hedge instrument being not well correlated to the change in the valuation of the underlying exposures being hedged; change in price of the underlying commodity; lack of market liquidity; insufficient counterparties to transact with; counterparty default; deficiency in systems or controls; human error; and the unenforceability of contracts.

There is risk that the consequences of hedging to protect against unfavourable market conditions may limit the benefit to us of commodity price increases or changes in interest rates and foreign exchange rates. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil, natural gas or refined products to fulfill our delivery obligations related to the underlying physical transaction.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3, 35 and 36 of the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

In 2020, for Cash Flow derivatives, we incurred a realized loss due to the settlement of benchmark prices relative to our risk management contract prices. For Optimization derivatives, the realized loss was from our decisions to store rather than sell our physical crude oil and condensate volumes as well as hedging activity related to the transportation of crude and condensate. Cenovus uses its marketing and transportation initiatives, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification, to inventory physical positions. At the time we make the decision to store crude oil and condensate volumes, the prices available for future periods we plan to sell in can be locked in and the improved margin realized in the future periods, which are superior to short-term prices. The risk management gains and losses offset corresponding fluctuations in revenues generated from the underlying physical sales.

Unrealized losses were recorded on our crude oil financial instruments in the twelve months ended December 31, 2020 primarily due to changes in commodity prices compared with prices at the end of the year and the realization of settled positions.

Transactions typically span across periods in order to execute the optimization strategy, and these transactions reside across both realized and unrealized risk management.

Sensitivities – Risk Management Positions

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices, with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuations in commodity prices on our open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to WTI and Condensate Hedges	**(44)**	**44**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**(2)**	**2**

For further information on our risk management positions, see Notes 35 and 36 of the Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

Financial instruments expose us to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our Board-approved *Credit Policy*.

Financial instruments also expose us to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to us if commodity prices, interest or foreign exchange rates change. These risks are managed through hedging limits authorized according to our *Market Risk Management Policy*.

Exposure to Counterparties

In the normal course of business, we enter into contractual relationships with suppliers, partners, lenders and other counterparties for the provision and sale of goods and services. If such counterparties do not fulfill their contractual obligations on a timely basis or at all, we may suffer financial losses, delays of our development plans or we may have to forego other opportunities which could materially impact our financial condition or operational results.

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Among other things, unpredictable financial markets, a sustained commodity price downturn, a change in market fundamentals, business operations, investor or lender sentiment towards our business and/or the industry in which we operate or credit rating, or significant unanticipated expenses, may impede our ability to secure and maintain cost-effective financing. An inability to access capital, on terms acceptable to Cenovus or at all, could affect our ability to make future capital expenditures, to maintain desirable ratios of debt (and Net Debt) to Adjusted EBITDA as well as debt (and Net Debt) to capitalization and to meet all of our financial obligations as they come due, potentially creating a material adverse effect on our financial condition, results of operations, ability to comply with various financial and operating covenants, credit ratings and reputation.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic, business, market and other conditions, some of which are beyond our control. If our operating and financial results are not sufficient to service current or future indebtedness, Cenovus may take actions such as reducing or suspending dividends, reducing or delaying business activities, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional capital that could have less favourable terms.

Our liquidity risk is mitigated through actively managing cash and cash equivalents, cash flow provided by operating activities, available credit facilities, and accessing the capital markets.

We are required to comply with various financial and operating covenants under our credit facilities and the indentures governing our debt securities. We routinely review our covenants to ensure compliance. In the event that we do not comply with such covenants, our access to capital could be restricted or repayment could be accelerated.

Credit Ratings

Our company and our capital structure are regularly evaluated by credit rating agencies. Credit ratings are based on our financial and operational strength and a number of factors not entirely within our control, including conditions affecting the oil and gas industry generally, industry risks associated with climate change and an energy transition and the state of the economy. There can be no assurance that one or more of our credit ratings will not be downgraded or withdrawn entirely by a rating agency.

A reduction in any of our credit ratings could adversely affect the cost and availability of borrowing, and access to sources of liquidity and capital. A failure by Cenovus to maintain current credit ratings could affect our business relationships with counterparties, operating partners and suppliers.

If one or more of our credit ratings falls below certain ratings thresholds, we may be obligated to post collateral in the form of cash, letters of credit or other financial instruments in order to establish or maintain business arrangements. Additional collateral may be required due to further downgrades below certain ratings thresholds. Failure to provide adequate credit risk assurance to counterparties and suppliers may result in foregoing or having contractual business arrangements terminated.

Foreign Exchange Rates

Fluctuations in foreign exchange rates between various currencies may affect our results. Global prices for crude oil, refined products, and natural gas are generally set in U.S. dollars, while many of our operating and capital costs are in Canadian dollars. A change in the value of the Canadian dollar relative to the U.S. dollar will increase or decrease revenues, as expressed in Canadian dollars, received from the sale of oil and refined products, and from some of our natural gas sales. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in our U.S. dollar denominated debt and related interest expense, as expressed in Canadian dollars. We may periodically enter into transactions to manage our exposure to exchange rate fluctuations. However, the fluctuations in exchange rates are beyond our control and could have a material adverse effect on our cash flows, results of operations and financial condition.

Interest Rates

We may be exposed to fluctuations in interest rates as a result of the use of floating rate securities or borrowings. An increase in interest rates could increase our net interest expense and affect how certain liabilities are recorded, both of which could negatively impact financial results. Additionally, we are exposed to interest rate fluctuations upon the refinancing of maturing long-term debt and potential future financings at prevailing interest rates.

We may periodically enter into transactions to manage our exposure to interest rate fluctuations.

Dividend Payment and Repurchase of Securities

The payment of dividends, continuation of Cenovus's dividend reinvestment plan and any potential repurchase by Cenovus of its securities is at the discretion of the Board, and is dependent upon, among other things, financial performance, debt covenants, satisfying solvency testing, our ability to meet financial obligations as they come due, working capital requirements, future tax obligations, future capital requirements, commodity prices and other business and risk factors set forth in this MD&A.

Disclosure Controls and Procedures and ICFR

Based on their inherent limitations, disclosure controls and procedures and ICFR may not prevent or detect misstatements, and even those controls determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on our business, financial condition, results of operations, cash flows, and our reputation.

Operational Risk

Operational risks are those risks that affect our ability to continue operations in the ordinary course of business. Our operations are subject to risks generally affecting the energy industry. To partially mitigate our risks, we have a system of standards, practices and procedures to identify, assess and mitigate safety, operational and environmental risk across our operations. In addition, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations. However, there can be no assurance as to the amount, if any, or timing of recovery under our insurance policies in connection with losses associated with these events and risks. Although we maintain insurance for a number of risks and hazards, we may not be insured or fully insured against all losses or liabilities that could arise from our assets or operations.

Health and Safety

The operation of our properties is subject to hazards of finding, recovering, transporting, refining, processing and marketing hydrocarbons including, but not limited to: blowouts; fires; explosions; railcar incident or derailment; gaseous leaks; migration of harmful substances; loss of containment; releases or spills, including releases or spills from shipping vessels at terminals or hubs and as a result of pipeline or other leaks; corrosion; epidemics or pandemics; and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, acts of vandalism and terrorism; and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites. Any of these hazards can interrupt operations, impact our reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems, cause environmental damage that may include polluting water, land or air, and may result in fines, civil suits, or criminal charges against Cenovus, any of which may have a material adverse effect on our business, financial condition, results of operations, cash flows, and our reputation.

Aviation Incidents

Cenovus's Offshore operations in Canada and China rely on regular travel by helicopter. A helicopter incident resulting in loss of life, facility shutdown or regulatory action could have a material adverse effect on our operations. This risk is managed through an aviation management process. Aviation Safety Reviews are conducted by third party specialist contractors to verify that helicopter service providers meet Cenovus's and industry standards with respect to aviation safety. The reviews include evaluation of aircraft type, effectiveness of the safety and maintenance management systems and competency and training programs for critical roles in the operation of helicopters. Helicopters chartered to support Offshore operations must be fit for service and as such are fitted with multiple redundant systems to address a wide range of potential in-flight emergencies. Additional measures specific to our challenging operating environments are specified in our design requirements including anti-icing and floatation systems effective for the maximum allowable sea height operating limits. Pilots are trained to address potential emergency situations through regular real-time and simulator training aligned with industry best practice.

Ice Management

Although extensive measures are in place to prevent incidents related to sea ice and icebergs, our offshore operations are at risk of incidents caused by icebergs which may interrupt operations, impact our reputation, cause loss of life, personal injury, or damage to equipment or the environment, and may result in regulatory action or litigation against us. We have several policies in place to protect people, equipment and the environment in the event of extreme weather conditions and adverse ice conditions. We have developed Adverse Weather Guidelines for the SeaRose floating production, storage and offloading vessel and continue to manage physical risk through engineering for extreme weather events.

Our Atlantic operations have a robust ice management program, which uses a range of resources including an industry shared ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment and Climate Change Canada, the Canadian Coast Guard and Canadian Ice Service. In addition, Atlantic operators employ a series of supply and support vessels to actively manage ice and icebergs. We also maintain a series of relationships with contractors on a stand-by basis, allowing the quick mobilization of additional resources as required. We regularly assess all aspects of our ice management program in order to ensure that the program continues to evolve as more information about the characteristics of ice and icebergs becomes available and as new technologies are developed.

Market Access Constraints and Transportation Restrictions

Our production is transported through various pipelines, marine and rail networks and our refineries are reliant on various pipelines and rail networks to receive feedstock. Disruptions in, or restricted availability of, pipeline service and/or marine or rail transport, could adversely affect crude oil, refined products and natural gas sales, projected production growth, upstream or refining operations and cash flows.

Interruptions or restrictions in the availability of these pipeline, marine and rail systems may also limit the ability to deliver production volumes and could adversely impact commodity prices, sales volumes and/or the prices received for our products. These interruptions and restrictions may be caused by, among other things, the inability of the pipeline, marine or rail networks to operate, or may be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. There can be no certainty that investments in new pipeline projects, which would result in an increase in long-term takeaway capacity, will be made by applicable third party pipeline providers that any applications to expand capacity will receive the required regulatory approval, or that any such approvals will result in the construction of the pipeline project or that such projects would provide sufficient transportation capacity and access to refining capacity. There is also no certainty that short-term operational constraints on the pipeline system, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail, marine transport and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on the pipeline system. In addition, our crude-by-rail and marine shipments may be impacted by service delays, inclement weather, railcar availability, railcar derailment or other rail or marine transport incidents and could adversely impact crude oil sales volumes or the price received for product or impact our reputation or result in legal liability, loss of life or personal

injury, loss of equipment or property, or environmental damage. In addition, rail and marine regulations are constantly being reviewed to ensure the safe operation of the supply chain. Should regulations change, the costs of complying with those regulations will likely be passed on to rail and/or marine shippers and may adversely affect our ability to transport crude-by-rail and/or marine transport or the economics associated with rail transportation. Finally, planned or unplanned shutdowns or closures of our refineries or of our refinery customers may limit our ability to deliver product with negative implications on sales and cash from operating activities.

Operational Considerations

Our operations are subject to all of the risks normally incidental to: (i) the storing, transporting, processing, and marketing of crude oil, refined products, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; (iii) the operation and development of crude oil and natural gas properties; and (iv) the operation of refineries, terminals, pipelines and other transportation and distribution facilities. These risks include but are not limited to: encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; fires; explosions; blowouts; loss of containment; gaseous leaks; power outages; migration of harmful substances into water systems; oil spills; uncontrollable flows of crude oil, natural gas or well fluids; failure to follow operating procedures or operate within established operating parameters; adverse weather conditions; pollution; freeze-ups and other similar events; the breakdown or failure of equipment, pipelines and facilities, information systems and processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); releases or spills from offshore operations, shipping vessels or other marine transport incidents; railcar incidents or derailments; failure to maintain adequate supplies of spare parts; the compromise of information technology and control systems and related data; operator error; labour disputes; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries, which may prevent the full utilization of the Company's facilities and pipelines; spills at truck terminals and hubs; spills associated with the loading and unloading of potentially harmful substances onto trucks; loss of product; unavailability of feedstock; price and quality of feedstock; epidemics or pandemics; and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, acts of sabotage and other similar events.

Producing and refining oil, bitumen and diluted bitumen requires high levels of investment and involves particular risks and uncertainties. Our oil sands operations are susceptible to reduced production, slowdowns, shutdowns, or restrictions on our ability to produce higher value products due to the interdependence of our component systems. Delineation of the resources, the costs associated with production, including drilling wells for SAGD operations, and the costs associated with refining oil can entail significant capital outlays. The operating costs associated with oil production are largely fixed in the short-term and, as a result, operating costs per unit are largely dependent on levels of production.

We do not insure against all potential occurrences and disruptions in respect of our assets or operations, and it cannot be guaranteed that our insurance coverage will be available or sufficient to fully cover any claims that may arise from such occurrences or disruptions. Our operations could also be interrupted by natural disasters or other events beyond our control. The occurrence of an event that is not fully covered by our insurance program could have a material adverse effect on our business, financial condition, results of operation and cash flows.

Reserves Replacement and Reserve Estimates

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels. Our financial condition, results of operations and cash flows are highly dependent upon successfully producing from current reserves and acquiring, discovering or developing additional reserves.

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows and revenue derived therefrom are based on a number of variable factors and assumptions including, but not limited to: product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including royalty payments and taxes, and environmental and emissions related regulations and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines, rail transportation and processing facilities, all of which may cause actual results to vary materially from estimated results.

All such estimates are to some degree uncertain and classifications of reserves are only attempting to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves may vary from current estimates and such variances may be material.

Estimates with respect to reserves that may be developed and produced in the future are often based on volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history.

Subsequent evaluation of the same reserves based on production history will result in variations, which may be material, in the estimated reserves.

The production rate of oil and gas properties tends to decline as reserves are depleted while the associated operating costs increase. Maintaining an inventory of developable projects to support future production of crude oil and natural gas depends on, among other things: obtaining and renewing rights to explore, develop and produce oil and natural gas; drilling success; completing long-lead time capital intensive projects on budget and on schedule; and the application of successful exploitation techniques on mature properties. Our business, financial condition, results of operations and cash flows are highly dependent upon successfully producing current reserves and adding additional reserves.

Cost Management

Our operating costs could escalate and become uncompetitive due to inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, higher steam-to-oil ratios in our oil sands operations, and additional government or environmental regulations. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial condition, results of operations and cash flows.

The cost or availability of oil and gas field equipment may adversely affect our ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices. Without compromising safety, overall quality and environmental impacts, we continually develop our approved suppliers base to provide undisrupted access to materials, equipment and services, while maintaining a competitive cost baseline via cost escalation mitigation strategies. A failure to secure equipment necessary to our operations for the expected price, on the expected timeline, or at all, may have an adverse effect on our financial condition, results of operations, and cash flows.

Competition

The Canadian and international energy industry is highly competitive in all aspects, including accessing capital, the exploration for, and the development of, new and existing sources of supply, the acquisition of crude oil and natural gas interests and the refining, distribution and marketing of oil and gas products. We compete with other producers and refiners, some of which may have lower operating costs or greater resources than our company does. Competing producers may develop and implement recovery techniques and technologies which are superior to those we employ. The oil and gas industry also competes with other industries in supplying energy, fuel and related products to consumers, including renewable energy sources which may become more prevalent in the future.

Project Execution

Cenovus manages a variety of oil, natural gas and refining projects across its global portfolio, including the current rebuild of our Superior Refinery. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of the Company's projects. These risks include, but are not limited to: our ability to obtain the necessary environmental and regulatory approvals; our ability to obtain favourable terms or to be granted access within land-use agreements; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; risk related to the accuracy of project cost estimates; our ability to finance capital and expenses; our ability to source or complete strategic transactions; the effect of COVID-19 on project execution and timelines; and the effect of changing government regulation and public expectations in relation to the impacts of oil and gas operations on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving performance targets and objectives. Failure to manage these risks could have a material adverse effect on our financial condition, results of operations and cash flows and may affect our safety and environmental record thereby negatively affecting our reputation and social license to operate.

Partner Risks

Some of our assets are not operated or controlled by us or are held in partnership with others, including through joint ventures. Therefore, our results of operations and cash flows may be affected by the actions of third-party operators or partners and our ability to control and manage risks may be reduced. We rely on the judgment and operating expertise of our partners in respect of the operation of such assets and to provide information on the status of such assets and related results of operations; however, we are, at times, dependent upon our partners for the successful execution of various projects.

Our partners may have objectives and interests that do not align with or may conflict with our interests. No assurance can be provided that the future demands or expectations of Cenovus relating to such assets will be satisfactorily met in a timely manner or at all. If a dispute with a partner or partners were to occur over the development and operation of a project or if a partner or partners were unable to fund their contractual share of

the capital expenditures, a project could be delayed and Cenovus could be partially or totally liable for its partner's share of the project.

SAGD Technology

Current technologies used for the recovery of bitumen can be energy intensive, including SAGD which requires significant consumption of natural gas in the production of steam used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using SAGD technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on our business, financial condition, results of operations and cash flows. There are risks associated with growth and other capital projects that rely largely or partly on new technologies, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. The success of projects incorporating new technologies cannot be assured.

Information Systems

We rely heavily on information technology, such as computer hardware and software systems, to properly operate our business. In the event we are unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data.

In the ordinary course of business, we collect, use and store sensitive data, including intellectual property, proprietary business information and personal information of our employees and third parties. Despite our security measures, our information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions, including natural disasters and acts of war. Any such breach could compromise information used or stored on our systems and/or networks and result in the loss, theft or exposure of confidential information related to retail credit card information, personnel files, exploration activities, corporate actions, executive officer communications and financial results. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, operational disruption, site shut-down, leaks or other negative consequences, including damage to our reputation, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

There is also a risk of cyber-related fraud whereby perpetrators attempt to take control of electronic communications or attempt to impersonate internal personnel or business partners to divert payments and financial assets to accounts controlled by the perpetrators. If a perpetrator is successful in bypassing Cenovus's cyber-security measures and business process controls, such cyber-related fraud could result in financial losses, remediation and recovery costs, and an adverse reputational impact.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact our personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility, terminal, pipeline, rail network, office or offshore vessel/installation owned or operated by Cenovus or any of our partners could result in the interruption or cessation of key elements of our operations. Outcomes of such incidents could have a material adverse effect on our results of operations, financial condition and business strategy. The risk to employees and board members due to ongoing social unrest in Hong Kong is being managed through reduced travel and increased awareness and monitoring of the situation. The potential for detention and/or incarceration of our employees/contractors entering or working in China remains, and as a result, review and reconsideration for travel into China has become a business/corporate process.

Leadership and Talent

Our success is dependent upon our Management, our leadership capabilities and the quality and competency of our talent. If we are unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our financial condition, results of operations and pace of growth.

Litigation

From time to time, we may be the subject of demands, disputes and litigation arising out of our operations. Claims under such litigation may be material or may be indeterminate. Various types of claims may be made including, without limitation, failure to comply with applicable laws and regulations, environmental damages, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, securities class actions, derivative actions, patent infringement and employment-related matters. We may be required to incur significant expenses or devote significant resources in defense against any such litigation, which could result in an unfavourable decision, including fines, sanctions, monetary damages, temporary suspensions of operations, or the inability to engage in certain operations or transactions. The outcome of such claims can be difficult to assess or quantify and may have a material adverse effect on our reputation, financial condition and results of operations. In

addition, we may be subject to or impacted by climate change related litigation. See “Climate Change Related Litigation” for discussion.

Indigenous Land and Rights Claims

Opposition by Indigenous groups to conduct our operations, development or exploratory activities in any of the jurisdictions in which we conduct business may negatively impact us in terms of public perception, diversion of Management’s time and resources, legal and other advisory expenses, and could adversely impact our progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. There are outstanding Indigenous and treaty rights claims, which may include Indigenous title claims, on lands where we operate, and such claims, if successful, could have a material adverse impact on our operations or pace of growth. No certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. In addition, the federal government has introduced legislation to implement the *United Nations Declaration on the Rights of Indigenous Peoples* (“UNDRIP”). Other Canadian jurisdictions have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP’s implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Regulatory Risk

The oil and gas industry and refining industry in general and our operations in particular are subject to regulation and intervention under federal, provincial, territorial, state and municipal legislation in the countries in which we conduct operations, development or exploratory activities in matters such as, but not limited to: land tenure; permitting of production projects; royalties; taxes (including income taxes); government fees; production rates; environmental protection controls; protection of certain species or lands; provincial and federal land use designations; the reduction of greenhouse gases (“GHGs”) and other emissions; the export of crude oil, natural gas and other products; the transportation of crude-by-rail or marine transport; the awarding or acquisition of exploration and production, oil sands or other interests; the imposition of specific drilling obligations; control over the development, abandonment and reclamation of fields (including restrictions on production) and/or facilities; and possibly expropriation or cancellation of contract rights. The implementation of new regulations or the modification of existing regulations could impact our existing and planned projects or increase capital investment, operating expenses or compliance costs, which could adversely impact our financial condition, results of operations and cash flows.

Regulatory Approvals

Our operations require us to obtain approvals from various regulatory authorities and there are no guarantees that we will be able to obtain all necessary licences, permits and other approvals that may be required to carry out certain exploration, development and operating activities on our properties. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder and Indigenous consultation, environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. Failure to obtain applicable regulatory approvals or satisfy any of the conditions thereto on a timely basis on satisfactory terms could result in delays, abandonment or restructuring of projects and increased costs.

Abandonment and Reclamation Cost Risk

Cenovus is subject to oil and gas asset abandonment, reclamation and remediation (“A&R”) liabilities for our operations, development and exploratory activities, including those imposed by regulation under federal, provincial, territorial, state and municipal legislation in the countries in which we conduct operations, development or exploratory activities.

In Alberta, the A&R liability regime includes the Orphan Well Fund, which is administered by the Orphan Well Association (the “OWA”). The OWA administers orphaned assets and is funded through a levy imposed on licensees, including Cenovus, based on their proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites in Alberta. The aggregate value of the A&R liabilities assumed by the OWA has increased in recent years and will remain at elevated levels until a significant number of orphaned wells are decommissioned by the OWA. In June of 2020, the OWA's powers were expanded to more effectively manage and

accelerate the clean-up of orphaned wells and associated infrastructure For instance, in certain circumstances the OWA would be allowed to act as an operator and take over production of abandoned wells. While the Alberta Energy Regulator's ("AER's") Site Rehabilitation Program is funding up to $1 billion of eligible abandonment and reclamation projects through December 31, 2022, it is uncertain how this program, or the recent expansion of the OWA's capabilities, will impact future orphan well liabilities being placed on the OWA. The OWA may seek additional funding for such liabilities from industry participants, including Cenovus.

The AER has broad discretion relating to liability management ratings, licence eligibility and licence transfers. Permit holders that are considered high risk and/or have relatively high levels of A&R obligations within their asset bases, may be negatively affected by increased financial requirements, including potential counterparties to Cenovus. This may result in future insolvencies and additional orphaned assets. In addition, this may impact Cenovus's ability to transfer our licences, approvals or permits, and may result in increased costs and delays or require changes to or abandonment of projects and transactions.

Cenovus has an ongoing environmental monitoring program at owned and leased retail locations and performs remediation where required. The costs of such remediation depend on a number of uncertain factors such as the extent and type of remediation required. Due to uncertainties inherent in the estimation process, it is possible that existing estimates may need to be revised and that conditions may exist at various retail locations that require future expenditures. Such future costs may not be determinable due to the unknown timing and extent of corrective actions that may be required.

For Offshore, the present value cost for decommissioning and abandonment of the offshore wells and facilities is estimated based on known regulations, procedures and costs today for undertaking the decommissioning, the majority of which is projected to be incurred in the 2030s. It is possible that these costs may change materially before decommissioning due to regulatory changes, technological changes, acceleration of decommissioning timelines, and inflation among other variables.

While the impact on Cenovus of any legislative, regulatory or policy decisions relating to the A&R liability regulatory regime in the jurisdictions in which we conduct operations, development or exploratory activities cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and materially and adversely affect, among other things, our business, financial condition, results of operations and cash flows.

Royalty Regimes

Our cash flows may be directly affected by changes to royalty regimes. The governments of the jurisdictions where we have producing assets receive royalties on the production of hydrocarbons from lands in which they respectively own the mineral rights and which Cenovus produces under agreement with each respective government. Government regulation of royalties is subject to change for a number of reasons, including, among other things, political factors. In Canada, there are certain provincial mineral taxes payable on hydrocarbon production from lands other than Crown lands. The potential for changes in the royalty and mineral tax regimes applicable in the jurisdictions in which Cenovus operates, or changes to how existing royalty regimes are interpreted and applied by the applicable governments, creates uncertainty relating to the ability to accurately estimate future royalty rates or mineral taxes and could have a significant impact on our business, financial condition, results of operations and cash flows. An increase in the royalty rates or mineral taxes in jurisdictions where we have producing assets would reduce our earnings and could make, in the respective jurisdiction, future capital expenditures or existing operations uneconomic. A material increase in royalties or mineral taxes may reduce the value of our associated assets.

Canada-United States-Mexico Agreement ("CUSMA")

On July 1, 2020, the new CUSMA entered into force, replacing the North American Free Trade Agreement ("NAFTA"). According to a Government of Canada technical summary of negotiated outcomes related to the energy sector, under CUSMA, the rule of origin applicable to heavy oil containing diluent has been relaxed to allow up to 40 percent of non-originating diluent that is added for the purpose of transportation in pipelines without affecting the originating status of the product, which will allow Canadian products to more easily qualify for duty-free treatment when imported into the U.S. The related CUSMA side letter on energy between Canada and the U.S. also promotes regulatory transparency and non-discrimination in access to or use of energy infrastructure, which may potentially benefit the Canadian heavy oil industry. While it is not yet known how certifications can be successfully substantiated, this is an improvement to the NAFTA origin rule.

The investor-state dispute settlement provisions will no longer be available to protect future investments of Canadians in the U.S. or U.S. investments in Canada. For three years after the termination of NAFTA, existing "legacy investments" will maintain their access to the investor-state dispute settlement under NAFTA Chapter 11.

Labour Risk

Cenovus depends on unionized labour for the operation of certain facilities and may be subject to adverse employee relations and labour disputes, which may disrupt operations at such facilities. As of February 1, 2021, approximately 6.1 percent of our employees were represented by unions under existing collective bargaining agreements with Cenovus's newly acquired operating subsidiaries. We cannot assure that strikes or work

stoppages will not occur. Any prolonged work stoppages may have a material adverse effect on our business, reputation, financial condition, results of operations and cash flows.

In addition, we may not be able to renew or renegotiate our subsidiaries' collective bargaining agreements on satisfactory terms or at all and a failure to do so may increase our costs. Moreover, employees who are not currently represented by unions may seek union representation in the future and efforts may be made from time to time to unionize other portions of our workforce. Any renegotiation of our existing collective bargaining agreements may result in terms that are less favourable to Cenovus, which may materially and adversely affect our financial condition, results of operations and cash flows.

Future unionization efforts or changes in legislation and regulations may result in labour shortages, higher labour costs, as well as wage, benefit, and other employment consequences, especially during critical maintenance and construction periods, all of which may increase our costs, reduce our revenues or limit our operational flexibility.

International Developments and Geopolitical Risk

Cenovus's business includes Asia Pacific Assets in the South China Sea and the Madura Strait offshore Indonesia, and includes cooperation agreements with China National Offshore Oil Corporation or its subsidiaries (collectively “CNOOC”), which also operates certain of these assets.

As a result, Cenovus is exposed to the financial and operational risks associated with uncertain international relations. Political developments impacting international trade, including trade disputes and increased tariffs, particularly between the U.S. and China and Canada and China, may negatively impact markets and cause weaker macroeconomic conditions or drive political or national sentiment, weakening demand for crude oil, natural gas and refined products. For example, U.S. government trade policy has resulted in, and could result in more, U.S. trading partners adopting responsive trade policy and may make it more difficult or costly for Cenovus to operate in and export our products to those countries.

Moreover, our operations may be materially adversely affected by political, economic or social instability or events, including the renegotiation or nullification of agreements and treaties, the imposition of onerous regulations, embargoes, sanctions, and fiscal policy, changes in laws governing existing operations, financial constraints, including currency restrictions and exchange rate fluctuations, unreasonable taxation and the behaviour of international public officials, joint venture partners or third-party representatives. Specifically, our Asia Pacific assets expose Cenovus to the effects of the changing U.S.-China and Canada-China relations, including escalating tensions and possible retaliations. It is possible that additional actions taken by the U.S. and Canada may limit or restrict foreign companies' ability to participate in projects and operate in certain sectors of the Chinese economy, including the energy sector.

On November 12, 2020, the former President of the United States signed an executive order prohibiting U.S. persons from engaging in transactions in the publicly traded securities of specified companies with alleged ties to the Chinese military. The prohibition is intended to be effective from January 11, 2021 to November 21, 2021. On December 3, 2020, CNOOC was added to the list of companies with alleged ties to the Chinese military. Although the executive order does not limit Cenovus's offshore operations in Asia, further U.S. sanctions against CNOOC may affect such operations, depending on the nature of such sanctions.

A new U.S. presidential administration took office in January 2021 and may implement domestic and foreign policy that could have a significant impact on Cenovus's financial condition or results of operations. We cannot accurately predict the implementation of U.S. or Canadian policy affecting any current or future activities by CNOOC, Cenovus's other international partners or Cenovus. Similarly, we cannot accurately predict whether U.S. restrictions will be further tightened or the impact of government action on Cenovus's offshore operations in Asia. It is possible that the U.S. or Canadian government may subject CNOOC or Cenovus's other international partners to restrictions or sanctions, which may adversely impact our offshore operations in Asia.

Moreover, it is possible that our partnership with CNOOC may deter certain investors from investing in Cenovus, or encourage certain investors to divest their existing holdings in Cenovus, which could have a negative impact on our share price and our ability to raise capital. It is also possible that as a result of our partnership with CNOOC, we may be subject to negative media attention which may affect investors' perception of Cenovus in Canada, the U.S. and globally, and which may negatively affect our share price.

In addition, Cenovus may be affected by changes to bilateral relationships, the frameworks and global norms that govern international trade, and other geopolitical developments. This includes acute shocks (such as civil unrest or sanctions) and chronic stresses (such as political or business disputes and other forms of conflict, including military conflict) that may pose longer-term threats to our business. Unilateral action by, or changes in relations between, countries in which we operate, including the U.S. and China, and such countries’ approach to multilateralism and trade protectionism can impact our ability to access markets, technology, talent and capital. Disruptions or unanticipated changes of this nature may affect our ability to sell our products for optimum value or access inputs required for effective operations and has the potential to adversely affect our financial performance.

Geopolitical events, such as a shift in the relationship, an escalation or imposition of sanctions, tariffs or other trade tensions between the U.S. and China and Canada and China, may affect the supply, demand and price of crude oil, natural gas and refined products and therefore our financial performance. The timing, extent and fallout

of the ongoing tensions between the U.S. and China and Canada and China remains uncertain and the impact on our business is unknown.

Shifts in global power relations may also introduce greater uncertainty with respect to issues requiring global co-ordination (such as climate change, trade agreements, tax regulation, freedom of navigation and technology regulation), as well as raise questions on the efficacy of and trust in international institutions, including those that underpin international trade. These types of changes may cause restrictions or impose costs on our business, and may inhibit our future opportunities or affect our financial condition.

Cenovus's financial performance, operations and business may be adversely affected by any of the foregoing risks associated with international relations and specifically those risks arising from evolving U.S.-China and Canada-China relations. The nature, extent and magnitude of the effect of dynamic trade relations on Cenovus cannot be accurately predicted and may have a material adverse impact on our business, prospects, financial condition, results of operations, cash flows, and reputation.

Climate-Related Risks

There is growing international concern regarding climate change and there has been a significant increase in focus on the timing and pace of the transition to a lower-carbon economy. Governments, financial institutions, insurance companies, environmental and governance organizations, institutional investors, social and environmental activists, and individuals, are increasingly seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends which, individually and collectively are intended to or have the effect of accelerating the reduction in the global consumption of carbon-based energy, the conversion of energy usage to less carbon-intensive forms and the general migration of energy usage away from carbon-based forms of energy.

Climate change and its associated impacts may increase our exposure to, and magnitude of, each of the risks identified in the Risk Management and Risk Factors section of this MD&A. Overall, Cenovus is not able to estimate at this time the degree to which climate change related regulatory, climatic conditions, and climate-related transition risks could impact the Company's financial and operating results. Our business, financial condition, results of operations, cash flows, reputation, access to capital, access to insurance, cost of borrowing, access to liquidity, ability to fund dividend payments and/or business plans may, in particular, without limitation, be adversely impacted as a result of climate change and its associated impacts.

Transition Risks – Policy & Legal

Climate Change Regulation

Cenovus operates in several jurisdictions that regulate or have proposed to regulate air pollutants, including GHG emissions. Some of these regulations are in effect while others remain in various phases of review, discussion or implementation. Uncertainties exist relating to the timing and effects of these emerging regulations, other contemplated legislation, including how they may be harmonized, making it difficult to accurately determine the cost impacts and effects on our suppliers. Additional changes to climate change legislation may adversely affect our business, financial condition, results of operations and cash flows, which cannot be reliably or accurately estimated at this time. In December 2020, the Government of Canada proposed increasing the carbon tax to $170/tonne carbon dioxide equivalent ("CO2e") by 2030. To reach that level, the price imposed on carbon will rise from the 2022 rate of $50/tonne CO2e by $15/tonne CO2e each year until 2030. If made into law, this may have a significant impact on Cenovus. Notably, several Canadian provinces have launched constitutional challenges to Canada's national carbon-pricing regime that were heard by the Supreme Court of Canada ("SCC") in September 2020; however, as of December 31, 2020, the SCC's decision had not yet been issued. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal "backstop" price of carbon applies. As of December 2020, the federal backstop applied in Alberta, Manitoba, New Brunswick, Ontario and to electricity generation and natural gas transmission pipelines in Saskatchewan.

In Alberta, facilities emitting over 100,000 tonnes of GHG emissions annually are subject to the *Technology Innovation and Emissions Reductions Regulation* ("TIER"), which is considered equivalent to the federal carbon-pricing system for 2020. Facilities also have the choice to opt in to TIER, thereby avoiding the federal fuel charge.

The Government of Canada is also committed to reducing methane emissions from the crude oil and natural gas sector by 40-45 percent from 2012 levels by 2025. Regulatory requirements for fugitive equipment leaks and venting from well completion and compressors came into force on January 1, 2020. Further restrictions on facility production venting restrictions and venting limits for pneumatic equipment come into force on January 1, 2023. Provinces may introduce provincial regulations, and if found to be at least equivalent with the federal scheme, shall be enabled through a federal equivalency agreement process. Alberta, British Columbia and Saskatchewan have such equivalency agreements in place.

The U.S. does not have federal legislation establishing targets for the reduction of, or limits on, GHG emissions. However, the federal Environmental Protection Agency ("EPA") has and may continue to promulgate regulations concerning the reporting and control of GHG emissions. Since 2010, the EPA's Greenhouse Gas Reporting Program ("GHGRP") requires any facility releasing more than 25,000 tonnes of CO2e emissions per year to report those emissions on an annual basis. In addition to reporting direct CO2e emissions, the GHGRP requires refineries to

estimate the CO2e emissions from the potential subsequent combustion of the refinery's products. The Biden Administration has indicated that it will rejoin the Paris Agreement and seek to implement its objectives with respect to GHG emissions, including short-term global emissions reductions and net-zero global emissions by mid-century, and that it will begin the process of developing U.S. emission reduction targets under the Paris Agreement. It is too early to assess what impact these actions may have on our business, financial condition or results of operations.

Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, potentially increasing the cost of construction, operation and abandonment. Other possible effects from emerging regulations may also include, but are not limited to: increased compliance costs; permitting delays; and substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses. Further, emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis, required emissions reductions may not be technically or economically feasible to implement, in whole or in part, and failure to have access to resources or technology to meet emissions reduction requirements or other compliance mechanisms may have a material adverse effect on our business resulting in, among other things, fines, permitting delays, penalties and the suspension of operations.

The extent and magnitude of any adverse impacts of current or additional programs or regulations beyond reasonably foreseeable requirements cannot be reliably or accurately estimated at this time, in part because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the timeframes for compliance. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to Cenovus.

Low Carbon Fuel Standards

Existing and proposed environmental legislation and regulation developed by certain U.S. states, Canadian provinces, the Canadian federal government and members of the European Union, regulating carbon fuel standards could result in increased costs and reduced revenue for Cenovus. The potential regulation may negatively affect the marketing of Cenovus's bitumen, crude oil or refined products, and may require us to purchase emissions credits in order to affect sales in such jurisdictions.

Environment and Climate Change Canada published a proposed regulatory framework in 2017 for the Clean Fuel Standard under the *Canadian Environmental Protection Act, 1999*, followed by a Regulatory Design Paper in December 2018 and a Proposed Regulatory Approach in June 2019. The proposed regulations for the Clean Fuel Standard were published in December 2020 and final regulations are planned to be published in late 2021, with new regulations under the Clean Fuel Standard targeted to come into force in 2022. The federal government has indicated that over time, the new Clean Fuel Standard would replace the current Renewable Fuels Regulations, which currently require producers and importers of gasoline, diesel fuel and heating distillate to acquire a certain number of renewable fuel compliance units commensurate with the volumes of fuel they produce or import. The proposed new regulatory framework would impose lifecycle carbon intensity requirements for certain liquid fuels and establish rules relating to the trading of compliance credits. Carbon intensity requirements under the Clean Fuel Standard regulation would become more stringent over time and would be differentiated between different types of renewable fuels to reflect the associated emissions reduction potential. Regulated parties, which may include fuel producers and importers, would have some flexibility with respect to how to achieve lower carbon fuels in Canada.

The Clean Fuel Standard regulation has the potential to impact our business, financial condition, results of operations and cash flows, though at this time it is difficult to predict or quantify any such impacts.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that impose stringent and costly requirements. The Environmental Protection Agency has implemented the Renewable Fuel Standard program that mandates that a certain volume of renewable fuel replace or reduce the quantity of certain petroleum-based transportation fuels sold or introduced in the U.S. Obligated Parties, including refiners or importers of gasoline or diesel fuel, achieve compliance with targets set by the U.S. Environmental Protection Agency by blending certain types of renewable fuel into transportation fuel, or by purchasing RINs from other parties on the open market. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. A RIN is a number assigned to each gallon of renewable fuel produced or imported into the U.S. RINs were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Cenovus and its refinery operating partners comply with the U.S. Renewable Fuel Standard by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market, where prices fluctuate. The Company cannot predict the future prices of RINs and renewable fuel blendstocks, and the costs to obtain the necessary RINs and blendstocks could be material. The Company's financial position, results of operations and cash flows may be materially impacted if we are required to pay significantly higher prices for RINs or blendstocks to comply with the RFS mandated standards and are unable to pass the compliance costs on to our customers.

Climate Change Related Litigation

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

Transition Risks – Market

Demand and Commodity Prices

The recent increase in focus on the timing and pace of the transition to a lower-carbon economy and resulting trends will likely affect global energy demand and usage, including the composition of the types of energy generally used by industry and individual consumers. However it is not currently possible to predict the timelines for and precise effects of this transition to a potential lower-carbon economy, which will depend on a multitude of factors including the ability to develop adequate replacement sources of energy, technology development and adaptation including in the area of transportation electrification, the ability to conceptualize, develop and commercialize technologies for the production, storage and distribution of adequate supplies of alternative energy, consumption patterns, global growth and industrial activity, in order to predict the longer-term demand trends for carbon-based energy sources. All of these factors are beyond our control and could result in a high degree of price volatility for each of crude oil, natural gas and refined products.

Access to Capital and Insurance

Capital markets are adjusting to the risks that climate change poses and as a result, our ability to access capital and secure necessary or prudent insurance coverage may also be adversely affected in the event that institutional investors, credit rating agencies, lenders and/or insurers adopt more restrictive decarbonization policies. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of our insurance policies could increase substantially. In some instances, coverage may be reduced or become unavailable. As a result, we may not be able to renew our existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all. The future development of our business may be dependent upon our ability to obtain additional capital, including debt and equity financing.

Transition Risks – Reputation

Reputation and Public Perception of Alberta Oil Sands

Development of the Alberta oil sands has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous engagement. Concerns about oil sands may, directly or indirectly, impair the profitability of our current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory, economic and operating uncertainty. Increased public opposition to the oil sands industry could lead to constrained access to insurance, liquidity and capital and changes in demand for Cenovus's products, which may impact revenue.

For example, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources.

Climate Change – Physical Risks

Extreme climatic conditions may also have material adverse effects on Cenovus's financial condition and results of operations. Weather and climate affect demand, and therefore, the predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, Cenovus's exploration, production and construction operations, and the operations of major customers and suppliers, can be affected by floods, forest fires, earthquakes, hurricanes, and other extreme weather events. This may result in cessation or diminishment of production, delay of exploration and development activities or delay of plant construction.

Cenovus operates in some of the harshest environments in the world, including offshore Newfoundland and Labrador. Climate change may increase the frequency of severe weather conditions in these locations including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Icebergs off the coast of Newfoundland and Labrador may threaten Atlantic oil production facilities, cause spills, damage assets, disrupt production or have human impacts.

Our other crude oil and natural gas production activities are also subject to chronic physical risks such as a shorter timeframe for our winter drilling program, changes in the water table and reduced access to water due to drought conditions. A systemic change in temperature or precipitation patterns could result in more challenging conditions for the construction of ice roads, execution of our winter drilling program and reclamation activities and could reduce the availability of water due to the increasing likelihood of drought conditions.

Environmental Risk

All phases of crude oil, natural gas and refining operations are subject to environmental regulation pursuant to a variety of federal, provincial, territorial, state and municipal laws and regulations in the jurisdictions in which we operate (collectively, the "environmental regulations"). Environmental regulations provide that wells, facility sites, refineries and other properties and practices associated with our operations be constructed, operated, maintained, abandoned, reclaimed and undertaken in accordance with the requirements set out therein. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications.

Cenovus anticipates that further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, increased compliance costs and approval delays for critical licences and permits. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus.

Compliance with environmental regulations requires significant expenditures. Our future capital expenditures and operating expenses could continue to increase as a result of, among other things, developments in our business, operations, plans and objectives and changes to existing, or implementation of new, environmental regulations. Failure to comply with environmental regulations may result in, among other things, the imposition of fines, penalties, environmental protection orders, suspension of operations, and could adversely affect our reputation. The costs of complying with environmental regulations may have a material adverse effect on our business, financial condition, results of operations and cash flows. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the crude oil and natural gas industry generally could reduce demand for crude oil and natural gas as well as shift hydrocarbon demand toward relatively lower carbon sources, increase compliance costs, lengthen project implementation times, and have an adverse effect on our business, financial condition, results of operations and cash flows.

Canadian Species at Risk Act

The Canadian federal *Species at Risk Act,* as well as provincial regulation regarding threatened or endangered species and their habitat may limit the pace and the amount of development or activity in areas identified as critical habitat for species of concern, such as woodland caribou. Recent petitions and litigation against the federal government in relation to their obligations under the *Species at Risk Act* have raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. In Alberta, a suite of initiatives have been undertaken to support caribou recovery, including the Draft Provincial Woodland Caribou Range Plan, which was released in 2017 but has not yet been finalized. Other initiatives include negotiation of conservation agreements under Section 11 of the *Species at Risk Act* (which codifies concrete measures to support the conservation of the species and the protection of its critical habitat), and the elaboration of sub-regional plans for the Cold Lake, Bistcho and Upper Smokey areas, to address recovery outcomes for certain caribou ranges. If plans and actions undertaken by the provinces are deemed insufficient to support caribou recovery, the federal legislation includes the ability to implement measures that would preclude further development or modify existing operations. The extent and magnitude of any potential adverse impacts of legislation on in situ oil sands project development and operations cannot be estimated, as uncertainty exists as to whether plans and actions undertaken by the provinces will be sufficient to support caribou recovery.

Canadian Federal Air Quality Management System

The Multi Sector Air Pollutants Regulations ("MSAPR"), issued under the *Canadian Environmental Protection Act, 1999*, seek to protect the environment and health of Canadians by setting mandatory, nationally-consistent air pollutant emission standards. The MSAPR are aimed at equipment-specific Base-Level Industrial Emissions Requirements ("BLIERs"). Nitrogen oxide BLIERs from our non-utility boilers, heaters and stationary engines are regulated in accordance with specified performance standards. We anticipate that the MSAPR will result in adverse impacts to Cenovus including but not limited to capital investment required to retrofit existing equipment and increased operating costs.

Canadian Ambient Air Quality Standards ("CAAQS") for nitrogen dioxide, sulphur dioxide, fine particulate matter and ozone were introduced as part of a national Air Quality Management System. Provinces may implement the CAAQS at the regional air zone level and air zone management actions may include more stringent emissions standards applicable to industrial sources from approval holders in regions where Cenovus operates that may result in adverse impacts including but not limited to capital investment related to retrofit existing facilities and increased operating costs.

Review of Environmental and Regulatory Processes

Increased environmental assessment obligations imposed by federal, provincial, territorial, state and municipal governments in the jurisdictions in which we conduct operations, development or exploratory activities may create risk of increased costs and project development delays. The extent and magnitude of any adverse impacts of changes to the legislation or policies on project development and operations cannot be estimated at this time.

The Canadian federal Bill C-69, an Act to enact the *Impact Assessment Act and* the *Canadian Energy Regulator Act,* to amend *the Navigation Protection Act (*renamed the *Canadian Navigable Water Act)* and to make consequential amendments to other Acts came into force in August 2019. In addition, Bill C-68, which amended the *Fisheries Act,* came into force at the same time.

The *Fisheries Act* amendments restored the previous prohibition against "harmful alteration, disruption or destruction of fish habitat" and the prohibition against causing the death of fish by means other than fishing and introduced several new requirements expanding the scope of protection and role of Indigenous groups and interests. These prohibitions may result in increased permitting requirements and time to obtain permits where Cenovus's operations potentially impact fish or fish habitat.

The *Canadian Navigable Waters Act* expanded its scope to all navigable waters, created greater oversight for navigable waters, and introduced requirements expanding the scope of protection and the role of Indigenous groups and interests. The broader application of the *Canadian Navigable Waters Act* may result in increased permitting requirements and time to obtain permits where Cenovus's operations potentially impact navigable waters.

The *Impact Assessment Act* ("IAA") established the Impact Assessment Agency of Canada, which leads and coordinates impact assessments for all designated projects. The IAA expands the assessment considerations beyond the environment to expressly include health, economic, social, and gender impacts, as well as considerations related to sustainability and Canada's climate change commitments.

Of note, the revised Project List outlined in the *Physical Activities Regulations* under the IAA captures in situ oil sands facilities with a bitumen production capacity of 2,000 m^3/day or more, and expansions of existing in situ oil sands facilities if the expansion would result in an increase in bitumen production capacity of 50 percent or more and a total bitumen production capacity of 2,000 m^3/day or more, but provides an exemption for a project proposed within a province in which there is a legislated limit on GHG emissions produced by the oil sands sector. For as long as the provincial government maintains the cap on oil sands emissions in Alberta and the cap has not been reached, Cenovus's in situ oil sands projects should be exempted from the application of the new federal impact assessment system, provided the above-noted conditions are met. However, other types of projects would undergo a federal assessment.

Water Licences

Cenovus utilizes fresh water in certain operations, which is obtained under licenses issued within each respective jurisdiction's regulations. If water use fees increase or a change under these licences reduces the amount of water available for our use, production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. There is no assurance that if we require new licences or amendments to existing licences, that these licences or amendments will be granted on favourable terms. This may adversely affect our business, including the ability to operate our assets and execute development plans.

Hydraulic Fracturing

Certain stakeholders have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and suggest that additional federal, provincial, state, territorial and/or municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

In addition, some areas of British Columbia and Alberta are experiencing increasing localized frequency of seismic activity which has been associated with oil and gas operations. Although the occurrence of seismicity in relation to oil and gas operations is generally very low, it has been linked to deep disposal of wastewater in the U.S. and has been correlated with hydraulic fracturing in Western Canada, which has prompted legislative and regulatory initiatives intended to address these concerns.

The Canadian federal government and certain provincial governments continue to review certain aspects of the existing scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. The Government of British Columbia released an action plan in 2019 based on the results of its scientific review of hydraulic fracturing and related impacts on water and seismic activity, which contains a number of actions to be implemented in a phased approach that will include increased monitoring, aquifers mapping and improvements to the regulatory regime. In Alberta, the AER has implemented seismic monitoring and reporting requirements for hydraulic fracturing operations in certain zones in some active oil and gas areas of Alberta.

Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to limitations or restrictions to oil and gas development activities, operational delays, increased compliance costs, additional

operating requirements, or increased third-party or governmental claims that could increase our cost of doing business as well as reduce the amount of natural gas and oil that Cenovus is ultimately able to produce from its reserves.

Cenovus ESG Focus Areas and Targets

Generally speaking, Cenovus's ESG targets depend significantly on our ability to execute our current business strategy, related milestones and schedules, and to successfully integrate the assets of Cenovus and the assets of Husky, each of which can be impacted by the numerous risks and uncertainties associated with our business and the industry in which we operate, as outlined in the Risk Management and Risk Factors section of this MD&A. We recognize that our ability to adapt to and succeed in a lower-carbon economy will be compared against our peers. Investors and stakeholders increasingly compare companies based on ESG-related performance, including climate-related performance. Failure to achieve our ESG targets, or a perception among key stakeholders that our ESG targets are insufficient, could adversely affect our reputation and our ability to attract capital and insurance coverage.

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

ESG Targets May Change Following Completion of the Arrangement

Completion of the Arrangement between Cenovus and Husky on January 1, 2021 resulted in a combination of the business activities previously carried on separately by each of Husky and Cenovus. Cenovus remains committed to world-class safety performance and ESG leadership following closing of the Arrangement. This includes completing additional analysis to set new ESG targets and ambitions for the combined business.

The ESG targets and ambitions of the combined business may not necessarily be the same as the targets or ambitions previously set by Cenovus. This is dependent, in large measure, on the completion of our review and analysis of the combined business following the completion of the Arrangement to determine whether such targets and ambitions remain appropriate for the combined business. In addition, the integration of Husky and Cenovus will require the dedication of substantial effort, time and resources on the part of management and staff of the combined company, which may divert focus from planned initiatives, including development and implementation of ESG targets and ambitions, towards other operational matters and could result in a disruption to, or delay in, the development and implementation of ESG targets and ambitions for the combined company or a shift in resources to other operational and business strategies.

The below sections include discussion of the ESG targets released by Cenovus in January 2020 which may be subject to change as a result of our determination of whether such targets and ambitions remain appropriate for the combined business.

Greenhouse Gas Emissions and Targets

Cenovus's future results and its ability to respond to and manage transition and physical risks of climate change may depend in part on our ability to adapt and apply our business model to a lower-carbon economy and to lower scope 1 and 2 GHG emissions (see Definitions section of this MD&A). Our ability to lower scope 1 and 2 GHG emissions on both an absolute basis and in terms of intensity in our operations and our long-term ambition of reaching net-zero emissions by 2050, are subject to numerous risks and uncertainties and our actions taken in implementing such targets may also expose us to certain additional and/or heightened financial and operational risks. Furthermore, our long-term ambition of reaching net-zero emissions by 2050 is inherently less certain due to the longer timeframe and certain factors outside of our control, including the commercial application of future technologies that may be necessary for us to achieve this long-term ambition.

A reduction in GHG emissions relies on, among other things, Cenovus's ability to develop, access and implement commercially viable and scalable emission reduction strategies and related technology and products. In addition, there are other operational risks that may hinder our ability to successfully meet our GHG emission targets and goals, including: unexpected impediments to, or effects of, the implementation of cogeneration plants at our Foster Creek and Christina Lake oil sands facilities and other investments in renewables, including in respect of available offsets and the availability and status of credit or offset for cogeneration facilities and other renewables; the effectiveness of air flue exchanges at Foster Creek and Christina Lake; our ability to electrify and otherwise adjust our operations in the Conventional segment; the unavailability of, or limited benefits from, technology that is expected to be commercially viable in the near term and their associated future benefits, including SAGD enhancement technologies, such as solvent-aided process and solvent-driven process technologies, carbon capture, utilization and storage technology and downhole technology improvements; and a failure to capture the anticipated benefits of continued technological development, industry collaboration and innovation to find solutions to reduce costs and GHG emissions intensity. In the event that we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or cost structure, or such strategies or

technologies do not perform as expected, we may be unable to meet our 2050 ambition on the current timelines, or at all.

In addition, achieving our GHG 2050 ambition will require capital expenditures and Company resources, with the potential that expectations regarding the costs required to achieve these targets and ambitions differ from our original estimates and the differences may be material. Furthermore, a shift of expenditures and resources towards such targets and ambition may negatively impact our business and operations. The cost of investing in emissions-intensity reduction technologies, and the resultant change in the deployment of resources and focus, could have a negative impact on our future operating and financial results.

Our GHG emissions targets and ambitions may also be subject to change as a result of Cenovus's determination of whether such targets and ambitions remain appropriate for the combined business.

Indigenous Engagement Target

Cenovus's Indigenous engagement target to spend $1.5 billion with Indigenous owned or operated businesses by the end of 2030 is subject to a number of financial, operational and efficiency risks relating to actions taken in implementing such target.

In addition, a failure or delay in achieving our Indigenous engagement target may adversely affect our relationship with neighboring Indigenous businesses and communities and our broader reputation. If we are unable to maintain a positive relationship with Indigenous communities near our operations, our progress and ability to develop and operate properties in line with our current business and operational strategies may be adversely impacted.

Our Indigenous engagement target may also be subject to change as a result Cenovus's determination of whether such a target remains appropriate for the combined business.

Land and Wildlife Target

Our land and wildlife targets are composed of the reclamation of 1,500 decommissioned well sites and $40 million in spend between 2016 and 2030 to restore more land within caribou ranges than disturbed by Cenovus's activity. Our ability to meet this target is subject to various environmental and regulatory risks, which could impose significant costs, restrictions, liabilities and obligations on Cenovus and limit our capacity to achieve such targets. See Abandonment and Reclamation Cost Risk above.

Financial risks including an increase in operating costs, changes to market conditions and access to additional capital, if needed, could result in our inability to fund, and ultimately meet, our land and wildlife targets on the current timelines, or at all. In addition, the development and implementation of range plans in these areas may have an impact on the pace and amount of development in these areas and could potentially increase costs for restoration or offsetting requirements, which could have a material adverse effect on our business, financial condition, reserves and results of operations. An inability to develop, execute on and complete ongoing reclamation plans and proactively manage our interactions with wildlife may adversely impact Cenovus's progress and ability to explore and develop properties.

Our land and wildlife targets may also be subject to change as a result of Cenovus's determination of whether such targets remain appropriate for the combined business.

Water Stewardship Target

Cenovus's ability to achieve a freshwater intensity of 0.1 barrels of freshwater per barrel of oil equivalent by the end of 2030 will depend on the commercial viability and scalability of relevant water reduction strategies and related steam and water usage technology and products. There are risks associated with relying largely or partly on new technologies, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. In the event we are unable to effectively and efficiently deploy the necessary technology, or such strategies or technologies do not perform as expected, achieving our stated target of reducing our water intensity could be interrupted, delayed or abandoned.

Our water stewardship targets may also be subject to change as a result of Cenovus's determination of whether such targets remain appropriate for the combined business.

Reputation Risk

We rely on our reputation to build and maintain positive relationships with investors and other stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions we take that influence public or key stakeholder opinions have the potential to impact our reputation which may adversely affect our share price, development plans and our ability to continue operations. There is increasing opposition from activist organizations and the public towards oil sands operations stemming from the perceived impact of the industry on the environment, climate change and GHG emissions. See Reputation and Public Perception of Alberta Oil Sands for further discussion.

Other Risks

Risks Related to the Arrangement

Entry into New Business Activities

Prior to the Arrangement, Cenovus's business was focused on the development and production of bitumen in northeast Alberta, natural gas and NGLs processing in the Conventional segment, and refining, transporting, marketing and selling crude oil, natural gas and NGLs in Canada and the U.S. Husky's business involved upstream development and production in Western Canada, offshore China, Indonesia and Atlantic Canada, and upgrading of heavy oil, refining crude oil, and marketing refined petroleum products in Canada and the U.S. The combined company's business comprises a combination of these businesses, which results in a different business and asset mix than the previous standalone businesses of Cenovus and Husky, respectively. The expansion of Cenovus's activities into new geographic and operational areas as a result of the Arrangement may present additional risks or significantly increase its exposure to one or more of Cenovus's present risk factors. The new business combination may also subject Cenovus to different business risks than those which were previously applicable to Cenovus and Husky as separate entities.

Possible Failure to Realize Anticipated Benefits of the Arrangement

Realizing the anticipated synergies from integrating the respective businesses of Cenovus and Husky depends in part on, among other things, successfully consolidating functions and integrating operations, systems, procedures and personnel in a timely and efficient manner. Achieving the benefits of the Arrangement also depends on Cenovus's ability to effectively capitalize on its scale, scope and leadership position in the oil sands and wider oil and natural gas industry, to realize the anticipated capital and operating synergies and to maximize the potential of its improved growth and capital funding opportunities.

The integration of the Cenovus and Husky assets to realize the benefits of the Arrangement will require the dedication of substantial management effort, time and resources which may divert Cenovus's Management's focus and resources from other strategic opportunities and operational matters. The integration process may result in the loss of key employees and the disruption of ongoing business and employee relationships that may adversely affect Cenovus's ability to achieve the anticipated benefits of the Arrangement. Cenovus may also incur additional expenses related to the Arrangement and the integration of Cenovus and Husky, which may limit Cenovus's ability to realize some or all of the anticipated benefits of the Arrangement.

If Cenovus is not able to successfully achieve the synergies associated with the Arrangement, or the cost to achieve these synergies is greater than expected, the anticipated benefits of the Arrangement may not be realized fully, or at all, may take longer to realize than expected, or may result in unforeseeable adverse effects. There can be no assurance that Cenovus will be able to achieve the synergies or realize the anticipated benefits of the Arrangement in a timely manner or at all. Failing to realize the anticipated benefits of the Arrangement may adversely affect Cenovus's financial condition, results of operations, reputation and share price.

Cenovus's Ability to Integrate Husky's Business with its Own

Given the increased scope and complexity of our operations, Cenovus may not be able to integrate Husky's operations or restructure Cenovus's previously existing business operations without encountering difficulties and delays. The integration process could result in disruption of existing relationships with suppliers, employees, customers and other constituencies of each company. Further, Cenovus will be required to maintain its financial and strategic focus while integrating Husky's business and avoid inconsistencies in implementing uniform standards, controls, procedures and policies, as appropriate. Our ability to integrate the businesses will depend in part on our ability to access or implement some or all of the personnel and technology necessary to efficiently and effectively operate Husky's assets. There can be no assurance that management will be able to successfully integrate the businesses to achieve any of the synergies or other benefits that are expected to result from the Arrangement.

The ongoing integration process involves numerous operational, strategic, financial, accounting, legal, tax and other risks and uncertainties associated with Cenovus's and Husky's business and operations. Difficulties in integrating our businesses may result in variations in expected performance, operational challenges or the failure to realize anticipated efficiencies on the expected timelines or at all. Cenovus's and Husky's existing businesses may also be negatively impacted by the combination.

Potential difficulties that may be encountered in the integration process include, among others: (i) the inability to successfully integrate the businesses in a manner that permits Cenovus to achieve the anticipated revenue and cost savings on the expected timelines or at all; (ii) complexities associated with managing a larger, more complex, multinational integrated business; (iii) achieving the anticipated operating synergies on the expected timelines or at all; (iv) integrating personnel at all levels of the company over multiple jurisdictions, effectively and efficiently; (v) difficulties integrating and maintaining relationships with Husky's industry contacts and existing business partners; and (vi) the disruption of, or the loss of momentum in, each of Cenovus's and Husky's ongoing businesses. Such challenges may prohibit Cenovus from successfully integrating Husky's business with its own or may materially delay the integration process. A failure to integrate the business on the expected timeline, or at all,

may have an adverse effect on Cenovus's financial condition, results of operations, and ability to realize the anticipated benefits of the Arrangement.

It is possible that the integration process could result in the loss of key employees to assist in the integration and operation of Husky and Cenovus, which may exacerbate integration challenges. Difficulties or delays in the integration process or the inability to partially or fully integrate Husky's business with our own could have a material adverse effect on our business, cash flow, operating results, financial condition, reputation and share price.

Costs Associated with the Integration of Cenovus's and Husky's Businesses

Cenovus may incur significant costs related to formulating and implementing ongoing integration plans, including facilities and systems consolidation costs and other employment-related costs. Cenovus will continue to assess the magnitude of these costs and additional unanticipated costs may be incurred in connection with the integration of the two companies. While Cenovus has accounted for a certain level of expenses, many factors beyond our control may affect the total amount or the timing of expenses associated with the integration process. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may not offset integration-related costs and achieve a net benefit in the near term, or at all. The costs described above and any unanticipated costs and expenses related to the integration may have an adverse effect on Cenovus's financial condition and results of operations.

Increased Indebtedness

Cenovus's increased indebtedness could have adverse consequences for Cenovus, including: reducing funds available for other business purposes; limiting Cenovus's ability to obtain additional financing for working capital, capital expenditures, product development, debt service requirements, acquisitions and general corporate or other purposes; restricting Cenovus's flexibility and discretion to operate its business; limiting Cenovus's ability to declare dividends; having to dedicate a portion of Cenovus's cash flows from operations to the payment of interest on its existing indebtedness and not having such cash flows available for other purposes; exposing Cenovus to increased interest expense on borrowings at variable rates; limiting Cenovus's ability to adjust to changing market conditions; placing Cenovus at a competitive disadvantage compared with its competitors with less debt; making Cenovus more vulnerable to a downturn in general economic conditions; and reducing funds available for capital expenditures that are important to Cenovus's business.

Dilutive Effect

The issuance of Cenovus common shares pursuant to the Arrangement had an immediate dilutive effect on the ownership interest of existing shareholders of Cenovus. The issuance of additional Cenovus common shares upon exercise, from time to time, of Cenovus Warrants or Cenovus Replacement Options issued to holders of Husky common shares and Husky options prior to the Arrangement will have a further dilutive effect on the ownership interest of shareholders of Cenovus. Such issuances will have a dilutive effect on Cenovus's earnings per share, which could adversely affect the market price of Cenovus common shares and may adversely impact the value of Cenovus shareholders' investments.

It is also expected that, from time to time, Cenovus will grant additional equity awards to our employees and directors under the combined Company's compensation plans. These additional equity awards will have a further dilutive effect on Cenovus's earnings per share, which could also negatively affect the market price of the Cenovus common shares.

Potential Undisclosed and Unforeseen Liabilities Associated with the Arrangement

In connection with the Arrangement, there may be liabilities that we failed to discover, underestimated or were unable to quantify in our due diligence conducted prior to the execution of the Arrangement Agreement and completion of the Arrangement. In addition, the Arrangement may subject Cenovus to unforeseen liabilities, including environmental and regulatory liabilities in Canada and other foreign jurisdictions. Cenovus may now be subject to claims related to Husky's operations and previous actions, including those of its current and former directors and employees. We may also be subject to adverse publicity associated with such matters, regardless of whether we are ultimately found responsible and may be required to incur significant expenses or devote significant resources in defense against any litigation of such claims. The outcome of any such litigation is uncertain and may negatively impact our financial condition, results of operations and reputation.

Pro Forma Financial Information may not be Indicative of Cenovus's Financial Condition or Results following the Arrangement

The *pro forma* financial information contained in Cenovus's public disclosure record is presented for illustrative purposes only as of its respective dates and may not be indicative of the current financial condition or results of operations of Cenovus. The unaudited *pro forma* financial information was derived from the respective historical financial statements of Cenovus and Husky, and certain adjustments and assumptions were made as of such dates to give effect to the Arrangement. The information upon which these adjustments and assumptions were made was preliminary and these kinds of adjustments and assumptions are difficult to make with complete accuracy. Accordingly, the combined business, assets, results of operations and financial condition may differ significantly

from those indicated in the unaudited *pro forma* financial information, and such variations may negatively impact our financial condition, results of operations and share price.

Pro Forma Reserves Information may not be Indicative of Cenovus's Reserves following the Arrangement

The *pro forma* reserves information included in the AIF is based on the reserves reports prepared by McDaniel and GLJ for Cenovus (the "2020 Cenovus Reserves Report"), and Husky's reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the COGE Handbook, and have been audited and reviewed by Sproule, an independent qualified reserves auditor (the "2020 Husky Reserves Report"), each effective December 31, 2020 (collectively, the "2020 Reserves Reports"). The reserves information presented in each of the 2020 Reserve Reports has been aggregated by Cenovus for illustrative purposes. The 2020 Reserves Reports were prepared using different assumptions and an independent reserves report effective December 31, 2020 was not prepared for the combined company. Therefore, the actual reserves of the combined company, if evaluated as of December 31, 2020 may differ from the *pro forma* reserves presented in the AIF. Cenovus and Husky, as stand-alone entities, have different operational and financial capabilities, which impacts their ability to develop reserves. And finally, there are systemic differences in the future development costs for each of Cenovus and Husky.

Further, were an independent reserves evaluation to be completed on our collective reserves as a result of the Arrangement, the assumptions underlying the 2020 Husky Reserves Report may be materially different from those assumptions used to evaluate the combined company's collective reserves. Our actual reserves could vary materially from these *pro forma* estimates and the Husky reserves acquired in connection with the Arrangement may be less than expected, which could adversely affect Cenovus's business, operations, financial results and share price.

Engineering, Reserves, Economic and Environmental Assessments in connection with the Arrangement may be Inaccurate

Acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. The assessments include a series of assumptions regarding such factors as recoverability and marketability of crude oil, natural gas and refined products, environmental restrictions and prohibitions regarding releases and emissions of various substances, future commodity prices and operating costs, future capital expenditures and royalties and other government levies that may be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic, engineering, economic, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Specifically, the 2020 Husky Reserves Report was prepared in respect of periods prior to completion of the Arrangement during which the crude oil and natural gas properties of Husky were operated on a stand-alone basis. Although Cenovus's Management believes the information contained in the 2020 Husky Reserves Report is reliable, Cenovus has not independently verified the historical information contained in such report and is unable to fully assess Husky's procedures for providing, assembling and reporting information to Sproule associated with Husky and its assets. In particular, the reserve and recovery information contained in the 2020 Husky Reserves Report is only an estimate and the actual production from, and ultimate reserves of, those properties may be greater or less than the estimates contained in such report.

Inclusion of Historical Information relating to Husky

The Arrangement was effected on January 1, 2021, and the integration of Cenovus's and Husky's business is ongoing. Cenovus has not yet completed independently evaluating and updating certain information relating to the assets, reserves and businesses acquired in the Arrangement and certain information contained in this MD&A and Cenovus's public disclosure record is based on historical information relating to Husky. Such historical information relating to Husky is derived from, among other things, previous Husky public disclosure and from information provided by current and former Husky directors, officers and employees. Much of the disclosure relating to Husky relates to periods prior to Cenovus's ownership of Husky, and therefore was generated by disclosure controls and procedures that may differ from those in place at Cenovus. Thus, information from the two companies may not have been generated and reported using equivalent standards. Further, Cenovus's Management's expectations about the combined entity's future performance reflect the current state of its information about Husky and its operations and there can be no assurance that such information is accurate in all material respects. Inaccuracies in historical information relating to Husky may cause Cenovus's financial and operational results to vary from our expectations, which may in turn adversely affect our financial condition, results of operations and share price.

Uncertainty related to Customers, Suppliers or Other Third Parties

As a result of the Arrangement, Cenovus may experience impacts on relationships with customers, suppliers or other third parties that may harm Cenovus's business and results of operations. Certain customers, suppliers or other third parties may seek to terminate or modify contractual obligations whether or not such contractual rights are triggered as a result of the Arrangement. There can be no guarantee that customers, suppliers or other third parties will remain with or continue to have a relationship with Cenovus or Husky or do so on the same or similar contractual terms. If any customers, suppliers or other third parties seek to terminate or modify contractual

obligations or discontinue their relationships with Cenovus or Husky, then Cenovus's business and results of operations may be adversely affected.

Any disruptions with third parties could limit our ability to achieve the anticipated benefits of the Arrangement or may be detrimental to Cenovus's and Husky's existing businesses, operations and financial conditions.

Risks Associated with the Cenovus Warrants

There can be no assurance that an active public market for the Cenovus Warrants will be sustained. If such a market is sustained, the market price of the Cenovus Warrants may be adversely affected by a variety of factors relating to Cenovus's business, including, without limitation, fluctuations in Cenovus's operating and financial results, the results of any public announcements made by Cenovus and Cenovus's failure to meet analysts' expectations. In addition, the market price of the Cenovus common shares will significantly affect the market price of the Cenovus Warrants. This may result in significant volatility in the market price of the Cenovus Warrants and may negatively impact the value of the Cenovus Warrants.

Holders of Cenovus Warrants will experience dilution if the combined company issues additional Cenovus common shares in future offerings or under outstanding Cenovus Replacement Options and Cenovus Warrants. Such dilution may adversely affect the market price of the Cenovus common shares and may negatively impact the value of Cenovus shareholders' investments.

Risks Related to Significant Shareholders of Cenovus

As of January 1, 2021, Hutchison Whampoa Europe Investments S.à r.l. ("Hutchison"), L.F. Investments S.à r.l ("L.F. Investments"), and ConocoPhillips own 15.7 percent, 11.5 percent and 10.3 percent of the common shares of Cenovus, respectively. Although each of Hutchison and L.F. Investments are subject to restrictions from selling or transferring Cenovus common shares through July 1, 2022 pursuant to the terms of their respective standstill agreement with Cenovus, the sale of Cenovus common shares held by any of Hutchison, L.F. Investments or ConocoPhillips into the market, either through open market trades on the Toronto and New York stock exchanges, through privately arranged block trades, or pursuant to prospectus offerings made in accordance with the respective registration rights agreement that each of Hutchison, L.F. Investments and ConocoPhillips have entered into with Cenovus, or market perception regarding ConocoPhillips' intention to sell Cenovus common shares, could adversely affect market prices for Cenovus common shares.

While Hutchison and L.F. Investments are each subject to certain voting covenants pursuant to the terms of a standstill agreement they each entered into with Cenovus in connection with the Arrangement, each of Hutchison and L.F. Investments may be able to impact certain matters requiring shareholder approval.

Amount of Contingent Payments Payable to ConocoPhillips

In connection with the Conoco Acquisition, we agreed to make contingent payments under certain circumstances. The amount of contingent payments vary depending on the Canadian dollar WCS price from time to time during the five year period following the closing of the Conoco Acquisition (May 17, 2017), and such payments may be significant. In addition, in the event that such further payments are made, this could have an adverse impact on our reported results and other metrics.

Tax Laws

Income tax laws, other laws or government incentive programs may in the future be changed or interpreted in a manner that adversely affects Cenovus, its financial results and its shareholders. Tax authorities having jurisdiction over Cenovus may disagree with the manner in which we calculate our tax liabilities such that its provision for income taxes may not be sufficient, or such authorities could change their administrative practices to Cenovus's detriment or the detriment of its shareholders. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects Cenovus and its shareholders.

U.S. Tax Risk

In January 2021, a new U.S. presidential administration took office. The new administration campaigned on a platform that included several tax provisions that could potentially be detrimental to Cenovus. Those provisions included an increase in the U.S. federal corporate tax rate and a new corporate minimum tax. While the ability of the new administration to enact tax laws is uncertain, it is possible that Cenovus's U.S. operations will be subject to increased levels of U.S. federal taxation in the future.

A discussion of additional risks, should they arise after the date of this MD&A, which may impact our business, prospects, financial condition, results of operation and cash flows, and in some cases our reputation, can be found in our subsequently filed MD&A, available on SEDAR at sedar.com, on EDGAR at sec.gov and cenovus.com.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement as either a joint operation or a joint venture requires judgment. Cenovus holds a 50 percent interest in WRB, a jointly controlled entity. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB. As a result, the joint arrangement is classified as a joint operation and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, "*Joint Arrangements*", the Company considered the following:

- The intention of the joint arrangement was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnerships. The past and future development of WRB is dependent on funding from the partners by way of partnership notes payable and loans.
- The WRB working interest relationship is operated whereby the operating partner takes product on behalf of the participants and is modified to account for the operating environment of the refining business.
- Phillips 66, as the operator, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnership from undertaking these roles themselves. In addition, the partnership does not have employees and, as such, are not capable of performing these roles.
- In the arrangement, output is taken by the partners, indicating that the partners have the rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangement.

Exploration and Evaluation Assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have reached a stage where technical feasibility and commercial viability cannot be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Identification of CGUs

CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretation. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining, crude-by-rail terminal, railcars, storage tanks, and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and reversals.

Determining the Lease Term

In determining the lease term, Management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. The assessment is reviewed if a significant event or a significant change in circumstances occurs which affects this assessment.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that, if changed, could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of COVID-19. The outbreak and subsequent measures intended to limit the pandemic contributed to significant declines and volatility in financial markets. The pandemic has adversely impacted global commercial activity, including significantly reducing worldwide demand for crude oil.

The full extent of the impact of COVID-19 on the Company's operations and future financial performance is currently unknown. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, its continued impact on capital and financial markets on a macro-scale and any new information that may emerge concerning the severity of the virus. These uncertainties may persist beyond when it is determined how to contain the virus or treat its impact. The outbreak presents uncertainty and risk with respect to the Company, its performance, and estimates and assumptions used by Management in the preparation of its financial results.

The outbreak and current market conditions have increased the complexity of estimates and assumptions used to prepare the annual Consolidated Financial Statements, particularly related to recoverable amounts.

In addition, the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the recoverable amount and could affect the carrying value of the related assets. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

Changes to assumptions could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test fair value less costs to sell and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Conventional segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses. Recoverable amounts for the Company's refining assets, crude-by-rail terminal and related ROU assets use assumptions such as throughput, forward commodity prices, market crack spreads, operating expenses, transportation capacity, future capital expenditures, supply and demand conditions and the terminal values used. Recoverable amounts for the Company's real estate ROU assets use assumptions such as real estate market conditions which includes market vacancy rates and sublease market conditions, price per square footage, real estate space availability and borrowing costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

2020 Upstream Impairments

The recoverable amounts of Cenovus's upstream CGUs were determined based on FVLCOD. Key assumptions in the determination of future cash flows from reserves include crude oil, NGLs and natural gas prices, costs to develop and the discount rate. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates at December 31, 2020. All reserves have been evaluated as at December 31, 2020 by the IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2020, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2021	2022	2023	2024	2025	Average Annual Increase Thereafter (percent)
WTI (US$/barrel)	47.17	50.17	53.17	54.97	56.07	2.0%
WCS (C$/barrel)	44.63	48.18	52.10	54.10	55.19	2.0%
Edmonton C5+ (C$/barrel)	59.24	63.19	67.34	69.77	71.18	2.0%
AECO (1) (C$/Mcf)	2.88	2.80	2.71	2.75	2.80	2.0%

(1) Assumes gas heating value of one million British thermal units per thousand cubic feet.

Discount and Inflation Rates

Discounted future cash flows are determined by applying a discount rate between 10 percent and 15 percent based on the individual characteristics of the CGU, and other economic and operating factors. Inflation is estimated at approximately two percent.

2020 Refining Impairments

The recoverable amount (Level 3) of the Borger CGU was determined using FVLCOD. The FVLCOD was calculated based on discounted after-tax cash flows using forward prices and cost estimates. Key assumptions in the determination of future cash flows included forward crude oil prices, forward crack spreads, future capital expenditures, operating costs, the terminal values and the discount rate. Forward crack spreads were based on quoted near-month contracts for WTI and spot prices for gasoline and diesel.

Crude Oil and Forward Crack Spreads

Forward prices are based on Management's best estimate and corroborated with third-party data. As at September 30, 2020, the forward prices used to determine future cash flows were:

- WTI forward prices used for 2021 to 2022 ranged from US$36.36 per barrel to US$50.84 per barrel and 2023 to 2025 ranged from US$49.66 per barrel to US$58.74 per barrel.
- WTI to West Texas Sour differential used for 2021 to 2022 ranged from US$0.37 per barrel to US$1.73 per barrel and 2023 to 2025 ranged from US$1.21 per barrel to US$1.81 per barrel.
- Group 3 forward market crack spread used for 2021 to 2022 ranged from US$11.56 per barrel to US$13.23 per barrel and 2023 to 2025 ranged from US$11.79 per barrel to US$16.58 per barrel.
- Subsequent prices were extrapolated using a two percent growth rate to determine future cash flows up to year 2035.

Discount and Inflation Rates

Discounted future cash flows are determined by applying a discount rate of 10 percent based on the individual characteristics of the CGU, and other economic and operating factors.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit-adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired and liabilities assumed in a business combination, including contingent consideration and goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparables and discounted cash flows which rely on assumptions such as forward commodity prices, reserves and resources estimates, production costs, volatility, Canadian-U.S. foreign exchange rates and discount rates. Changes in these variables could significantly impact the carrying value of the net assets.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2020.

New Accounting Standards and Interpretations not yet Adopted

There are new standards, amendments to accounting standards and interpretations that are effective for annual periods beginning or after January 1, 2021 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2020. These standards and interpretations are not expected to have a material impact on our Consolidated Financial Statements. The standard applicable to us is as follows and will be adopted on its respective effective date:

Interest Rate Benchmark Reform

On August 27, 2020, the IASB published Interest Rate Benchmark Reform – Phase 2 (Amendments to IFRS 9, "*Financial Instruments*", IAS 39, "*Financial Instruments: Recognition and Measurement*", IFRS 7, "*Financial Instruments: Disclosures*", IFRS 4, "*Insurance Contracts*" and IFRS 16) ("IBOR Phase 2 Amendments"), which provides clarity on the changes after the reform of an interest rate benchmark. The amendments are effective for annual periods beginning on or after January 1, 2021, with early application permitted. The IBOR Phase 2 Amendments primarily relate to the modification of financial instruments, allowing for a practical expedient for modifications required by the reform. The practical expedient for modifications is accounted for by updating the effective interest rate without modification of the financial instrument and is subject to satisfying all qualifying criteria. We expect the IBOR Phase 2 Amendments will not have a significant impact on our Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of ICFR and disclosure controls and procedures ("DC&P") as at December 31, 2020. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2020.

The effectiveness of our ICFR was audited as at December 31, 2020 by PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2020.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

SUSTAINABILITY

At Cenovus, sustainability is essential to the way we do business. It means creating a safe and inclusive workplace, partnering with local and Indigenous communities, and innovating to minimize our impact on the environment. We believe striking the right balance among environmental, economic and social considerations creates long-term value.

To support our sustainability performance, our *Sustainability Policy* guides our activities in the areas of: Leadership and Governance, People, Environment, Stakeholder Engagement, Indigenous Engagement, and Community Involvement and Investment.

Cenovus is committed to world-class safety performance and ESG leadership. This includes ambitious ESG targets, robust management systems and transparent performance reporting. The Company will continue working to earn its position as a global energy supplier of choice by advancing clean technology and reducing emissions intensity. This includes the ambition of achieving net zero emissions by 2050. Cenovus will also continue building upon its strong local community relationships, with a focus on Indigenous economic reconciliation.

The targets Cenovus released in 2020 for its key ESG focus areas are the product of robust processes to ensure alignment with the Company's business plan and strategy. Cenovus remains committed to pursuing ESG targets now that it has completed the Arrangement with Husky and will undertake a similarly thorough analysis before setting meaningful targets for the new portfolio. Once that work is complete in 2021 and approved by the Board, the new targets and plans to achieve them will be disclosed.

We published our 2019 ESG report in July 2020 to report on our management efforts and performance across the areas within our *Sustainability Policy* that are important to our stakeholders. Our ESG report is available on our website at cenovus.com.

OUTLOOK

We expect 2021 to be a challenging time for our industry and the global economy in general due to the impacts of COVID-19. With the continued uncertainty around COVID-19 and the scale of resurgence of COVID-19 cases, we anticipate crude oil and refined products demand to be volatile in 2021 with recovery dependent on the success of economic relaunches. We anticipate that an increase in demand for refined products will be an early indicator of recovery. Our top priority will be to maintain the strength of our balance sheet. We have ample liquidity, top-tier assets which we are able to effectively manage to respond to price signals, one of the lowest cost structures in the industry and have demonstrated our ability to reduce discretionary capital, all of which should allow us to continue to adapt to these challenges.

We continue to monitor the overall market dynamics to assess how we manage our Upstream production levels. Our assets can respond to market signals and ramp up production accordingly. Our decisions around production levels and refinery crude run rates will be focused on maximizing the value we receive for our products. We expect our 2021 annual Upstream production to average between 730,000 BOE per day and 780,000 BOE per day and total Downstream throughput of 500,000 barrels per day to 550,000 barrels per day.

With the close of the Arrangement, we estimated approximately $600 million in annual corporate and operating synergies and approximately $600 million in capital allocation synergies to be achievable. The 2021 budget positions us to achieve about $400 million of the estimated annual corporate and operating synergies and all of the estimated capital allocation synergies this year. Over the longer-term, we anticipate additional cost savings and margin enhancements based on further physical integration of upstream assets with downstream assets, which is expected to shorten the value chain and reduce condensate costs associated with heavy oil transportation. We continue to look for additional opportunities to reduce operating, capital, and G&A spending and increase our margins through strong operating performance and cost leadership while focusing on safe and reliable operations.

Given the challenges faced by our industry and the global economy and the closing of the Arrangement with Husky, achieving cumulative free funds flow of approximately $11 billion through 2024, as disclosed in our news release dated October 2, 2019, is under evaluation. We expect to develop a new five-year business plan for the Company later this year.

The following outlook commentary is focused on the next twelve months.

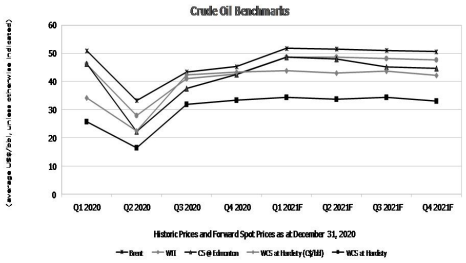
Commodity Prices Underlying our Financial Results

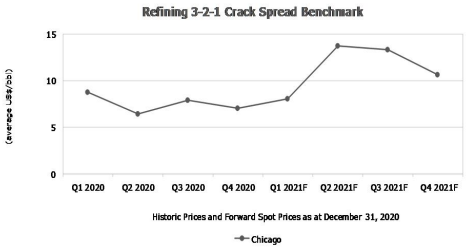
Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for light crude oil prices will be tied primarily to the supply and demand response to the current uncertain price environment, the impact of oversupply, and global demand impacts amid COVID-19 concerns;
- Crude oil and refined product price volatility is expected to continue due to crude demand destruction as a result of COVID-19;
- The effectiveness and successful distribution of vaccines will be key to the pace of oil demand recovery;
- The degree to which OPEC+ members (including Russia) continue to maintain crude oil production cuts;
- We expect that the WTI-WCS differential in Alberta will remain largely tied to the extent to which supply cuts are sustained, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, the completion of the Trans Mountain Expansion project, and the level of crude-by-rail activity; and
- We expect refining market crack spreads in 2021 to remain weak relative to normal as a result of significantly reduced refined products demand due to COVID-19, particularly in the first half of the year. Refining market

crack spreads are expected to continue to fluctuate, adjusting for seasonal trends and refining run cuts in North America.

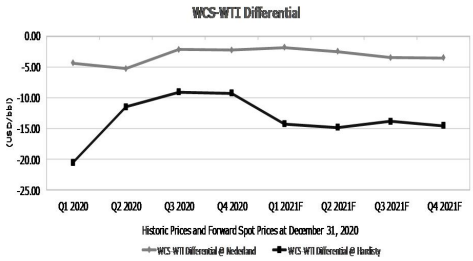
Natural gas and NGLs production associated with our Conventional assets provide improved upstream integration for the fuel, solvent and blending requirements at our Oil Sands operations.

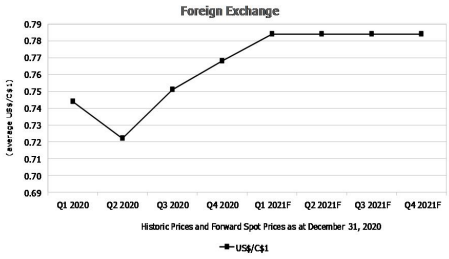




Natural gas prices have been challenged due to weaker demand as a result of COVID-19, but the forward curve is showing that the market expects AECO prices to rebound into 2021. Production declines from both associated gas and dry gas, along with rebounding U.S. demand and liquified natural gas exports, should tighten North American gas fundamentals in 2021 and result in stronger prices than 2020 on an annual basis.

We expect the Canadian dollar to continue to be tied to crude oil prices, the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise or lower benchmark lending rates relative to each other, and emerging macro-economic factors. The Bank of Canada lowered its benchmark lending rate twice in 2020 to address the impacts of COVID-19 and is expected to continue to hold the interest rate until 2023.





Our upstream crude oil production and most of our downstream refined products are exposed to movements in the WTI crude oil price. With the closing of the Arrangement, our exposure has grown on both the upstream and downstream sides of our business.

Our refining capacity is now focused in the U.S. Midwest along with smaller exposures to the USGC and Alberta. Cenovus is exposed to the crack spread in all of these markets.

Our exposure to crude differentials includes light-heavy and light-medium price differentials. Light-medium price differential exposure is focused on light-medium crudes in the U.S. Midwest market region where we have refining capacity, and to a lesser degree in the USGC and Alberta. Our exposure to light-heavy crude oil price differentials is composed of a global light-heavy component, a regional component in markets we transport barrels to, as well as the Alberta differential, which is subject to transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of crude oil and refined product prices and differentials through the following:

- Transportation commitments and arrangements – using our existing firm service commitments for takeaway capacity and supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets;
- Integration – having heavy oil refining capacity capable of processing Canadian heavy oil. From a value perspective, our refining business positions us to capture value from both the WTI-WCS differential for Canadian crude oil as well as from spreads on refined products;
- Marketing agreements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners;
- Dynamic storage – our ability to use the significant storage capacity in our oil sands reservoirs provides us flexibility on timing of production and sales of our inventory. We will continue to manage our production rates

in response to pipeline capacity constraints, voluntary and mandated production curtailments and crude oil price differentials;
- Traditional crude oil storage tanks in various geographic locations; and
- Financial hedge transactions – limiting the impact of fluctuations in crude oil and refined product prices by entering into financial transactions related to our exposures.

Key Priorities For 2021

We recently developed and shared updated guidance on January 28, 2021. In the current commodity price environment, we continue to focus on maintaining balance sheet strength and liquidity. Enhancing our financial resilience and flexibility while continuing to deliver safe and reliable operations will continue to be a top priority during these uncertain times.

Our corporate strategy focuses on maximizing shareholder value through cost leadership and realizing the best margins for our products. We expect to remain focused on disciplined capital investment allocation among the full suite of assets for the Company, and continued cost leadership to achieve margin improvement and environmental benefits.

Safe and Reliable Operations

Safe and reliable operations are our number one priority. Safety continues to be a core value that informs all of the decisions we make. We will continue to promote a safety culture in all aspects of our work and use a variety of programs to keep safety top of mind at all times.

Capture Synergies and Maintain Cost Leadership

The combination with Husky will further improve cost structure. The 2021 budget positions us to achieve about $400 million of annual corporate and operating synergies and an estimated $600 million in capital allocation synergies in 2021.

The annual corporate and operating cost synergies is well underway and is expected through the consolidation of information technology systems, eliminating other service overlaps, and through reductions to combined workforce and corporate overhead costs. Immediate efficiencies are also expected by implementing best practices from each company, including applying Cenovus's operating expertise to Husky's oil sands assets, leveraging the increased portfolio's scale, and pursuing commercial and contract-related efficiencies on transportation, storage, and logistics marketing and blending opportunities.

Over the longer term, we anticipate additional cost savings and margin enhancements based on further physical integration. The integration of Cenovus's upstream assets with Husky's downstream and transportation, storage, and logistics portfolio is expected to shorten the value chain and reduce condensate costs associated with heavy oil transportation over the longer term.

We continue to achieve improvements in our operating and G&A costs. In 2021, we will continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating and G&A cost reductions.

Disciplined Capital Investment

We released our 2021 guidance on January 28, 2021 for the Company and anticipate our total capital expenditures to be between $2.3 billion and $2.7 billion, including sustaining capital of approximately $2.1 billion and costs of $520 million to $570 million (excluding insurance proceeds) for the Superior Refinery rebuild. We will continue to be disciplined with our capital. The 2021 guidance is available on our website at cenovus.com.

Oil Sands capital investment for 2021, including Christina Lake, Foster Creek, Sunrise and Tucker oil sands projects, as well as the Lloydminster thermal projects and Cold and Enhanced Oil Recovery, is forecast to be between $850 million and $950 million. Oil Sands capital is primarily for sustaining production focused at Christina Lake, Foster Creek and the Lloydminster thermal assets. Our Oil Sands production is expected to range between 524,000 and 586,000 barrels per day for 2021.

Our Conventional segment capital investment is forecasted to be between $170 million and $210 million. This includes economic development in various plays to generate strong returns, improve underlying cost structures through volume enhancement and offset declines. Production is expected to range between 132,000 and 151,000 BOE per day for 2021.

Our Offshore segment, including operations and exploration prospects in the Asia Pacific region and Atlantic Canada region, capital investment is expected to be between $200 million and $250 million. This capital spend includes planned wells in China and continued development of the fields in the MDA-MBH and MDK fields in the Madura Strait, as well as baseline preservation capital for the West White Rose Project, which has been deferred for 2021 while we continue to evaluate options. Working Interest production from our Offshore segment is expected to range between 61,000 and 72,000 barrels per day.

In 2021, the Downstream segment, composed of Canadian and U.S. Manufacturing and Retail, we expect to invest between $1.0 billion and $1.2 billion and will continue to focus on refining reliability and maintenance, safety projects and high-return optimization opportunities as well as between $520 million and $570 million for the Superior rebuild project. The rebuild project will further improve our integration while reducing the Company's

exposure to WTI-WCS location differentials. Downstream throughput is expected to be in the range of 500,000 barrels per day to 550,000 barrels per day.

We expect to invest between $75 million and $100 million of corporate capital in 2021 across the Company.

In 2021, we plan to achieve capital allocation synergies across the Company by optimizing sustaining capital to the highest quality assets while maintaining safe and reliable operations across our portfolio.

As at December 31, 2020, our Net Debt position was $7.2 billion. The estimated incremental annual free funds flow from identified near-term synergies with the closing of the Arrangement is expected to accelerate balance sheet deleveraging. Through a combination of cash on hand and available capacity on our committed credit facilities and demand facilities, we have approximately $10.4 billion of liquidity under the combined company. In addition, WRB has available capacity of approximately $70 million, for Cenovus's proportionate share, on its demand facilities. We will continue to focus on allocating free funds flow to reduce Net Debt to less than $10 billion and target a longer-term Net Debt level at or below $8 billion.

Maintaining Financial Resilience

We have top-tier assets, one of the lowest cost structures in our industry and a strong balance sheet, all of which position us to withstand the challenges of the current market environment. Our capital planning process is flexible, and spending can be reduced in response to commodity prices and other economic factors so we can maintain our financial resilience. The Arrangement removes a significant amount of exposure to WTI-WCS location differentials and reduces commodity price volatility. Our financial framework and flexible business plan allow multiple options to manage our balance sheet. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in 2021.

The Company's priority will be to maximize free funds flow by focusing investments on sustaining capital expenditures which will position us to direct available free funds flow to the balance sheet and allow us to achieve a Net Debt target of $10 billion which approximates a Net Debt to Adjusted EBITDA target of less than 2.0 times, without the need for asset dispositions.

The low funds flow volatility, breakeven prices and corporate sustaining costs supports an investment grade profile and lower cost of capital through the commodity price cycle. We remain committed to maintaining our investment grade credit ratings.

Shareholder Returns

After achieving our balance sheet objectives, the Company's free funds profile is expected to enable sustainable growth in shareholder distributions. The Board declared a first quarter dividend of $0.0175 per common share, payable on March 31, 2021, to common shareholder of record as of March 15, 2021. The Board declared a first quarter dividend on the Series 1, 2, 3, 5, and 7 preferred shares, payable on March 31, 2021, in the amount of $8 million.

ESG

We are committed to ESG leadership. This includes ambitious ESG targets, robust management systems and transparent performance reporting. The Company will continue working to earn its position as a global energy supplier of choice by advancing clean technology and reducing emissions intensity. This includes the ambition of achieving net zero emissions by 2050. We will also continue building upon our strong local community relationships, with a focus on Indigenous economic reconciliation.

The targets Cenovus released in 2020 for its key ESG focus areas are the product of robust processes to ensure alignment with the company's business plan and strategy. We remain committed to pursuing ESG targets now that we have completed the Arrangement with Husky and will undertake a similarly thorough analysis before setting meaningful targets for the new portfolio. Once that work is complete in 2021 and approved by the Board, the new targets and plans to achieve them will be disclosed.

ADVISORY

Oil and Gas Information

The estimates of Cenovus's reserves were prepared effective December 31, 2020 by IQREs, based on the COGE Handbook and in compliance with the requirements of NI 51-101. Estimates are presented using the IQRE Average forecast prices and costs dated January 1, 2021 price forecasts. For additional information about our reserves and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2020.

Total proved reserves and total proved plus probable reserves for Cenovus and Husky are based on a simple summation of reserves prepared independently for each company. Cenovus has not constructed a consolidated reserves report of the combined assets of Cenovus and Husky, and has not engaged an independent reserves evaluator to produce such a report in accordance with NI 51-101. Reserves calculated for the combined company could be materially different than reserves calculated by adding the reserves of the two companies. The anticipated increase in reserves for the combined company may be more or less than anticipated, and the difference could be material.

Cenovus and Husky employed different methodologies to estimate their reserves information for the year ended December 31, 2020. All of Husky's oil and gas reserves estimates were prepared by internal qualified reserves evaluators using a formalized process for determining, approving and booking reserves. As a result, the actual reserves of Cenovus (after giving effect to the Arrangement), if calculated as of December 31, 2020 by an independent reserves evaluator in accordance with NI 51-101, may differ from the anticipated total proved reserves and total proved plus probable reserves of the combined company for a number of reasons, and such differences may be material. Barrels of Oil Equivalent – natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Forward-looking Information

This document contains certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking information") within the meaning of applicable securities legislation, including the *U.S. Private Securities Litigation Reform Act of 1995*, about our current expectations, estimates and projections about the future, based on certain assumptions made by us in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking information in this document is identified by words such as "achieve", "aim", "anticipate", "believe", "can be", "capacity", "committed", "commitment", "continue", "could", "deliver", "drive", "enhance", "ensure", "estimate", "expect", "focus", "forecast", "forward", "future", "guidance", "maintain", "may", "objective", "outlook", "plan", "position", "potential", "priority", "re-establishing", "strategy", "should", "target", "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: strategy and related milestones; schedules and plans; anticipated benefits of the Arrangement, including: achieving $1.2 billion of incremental annual free funds flow comprised of approximately $600 million in annual corporate and operating synergies and approximately $600 million in annual sustaining capital allocation synergies independent of commodity prices with the majority of annual savings achieved within the first year of combined operations and the full amount achieved within year two, the impact of the Arrangement on certain reserves data and other oil and gas information, including any *pro forma* information, the planned amalgamation of Cenovus and Husky, achieving longer term cost savings and margin enhancements based on further physical integration, reducing our exposure to Alberta heavy oil price differentials while maintaining exposure to global commodity prices, reducing condensate costs associated with heavy oil transportation over the longer term, accelerating balance sheet deleveraging, achieving sustainable growth in shareholder distributions; improving efficiencies to drive incremental capital, operating and G&A cost reductions; the ability of our assets to respond to market signals and ramp up production accordingly; statements and expectations relating to our 2021 budget; our ability to partially mitigate the impact of crude oil and refined product differentials through transportation commitments, integration, marketing agreements, dynamic storage, traditional storage tanks and financial hedge contracts; maintaining an investment grade credit rating; achieving Net Debt to Adjusted EBITDA target of less than 2.0 times without the need for asset dispositions; our focus on allocating free funds flow to reduce Net Debt to less than $10 billion and targeting a longer-term Net Debt level at or below $8 billion; focus on maximizing shareholder value through disciplined capital investment and cost leadership to realize the best margins for our products and environmental benefits; maintaining liquidity, delivering a stable cash flow through price cycles and preserving a resilient balance sheet by reducing spending while maintaining safe and reliable operations; the expected production levels of our business segments in 2021; longer-term focus on sustainably growing shareholder returns and reducing Net Debt as well as continuing to integrate ESG considerations into our business plan; maintaining a strong balance sheet to help

Cenovus navigate through commodity price volatility; evaluating disciplined investment in our portfolio against dividends, share repurchases and achieving and maintaining the optimal debt level while targeting investment grade status; focusing investment on areas where we believe we have the greatest competitive advantage; plan to achieve our strategy by leveraging our strategic focus areas including our oil sands, conventional oil and natural gas assets, marketing, transportation and refining portfolio, and our people; our 2020 capital investment plan, operating cost reductions and G&A reductions enhances our financial resilience and financial capability to maintain our base business, deliver safe and reliable operations and to continue to challenge our cost structure in the face of these unprecedented conditions; our ability to reduce spending in response to commodity prices and other economic factors in order to maintain our financial resilience; ample liquidity and runway to sustain operations through a prolonged market downturn; anticipated volatility of demand and crude oil prices through 2021 as a result of continued uncertainty around COVID-19, with crude oil and refined products demand and recovery dependent on the success of economic relaunches and the overall supply and demand balance; maintaining a high level of capital discipline and managing our capital structure to help ensure the Company has sufficient liquidity through all stages of the economic cycle; demand for refined product being an early indicator of recovery from the impact of COVID-19; increases in staff levels at sites and offices will continue to be achieved in accordance with guidance received from the applicable federal, provincial, state and local governments and public health officials; expected recovery of the price of and demand for crude oil and refined products over the longer term as COVID-19 vaccines are administered and economies re-open from the impacts of the pandemic; expected timing for oil sands expansion phases projections for 2021 and future years and our plans and strategies to realize such projections; the reduction of transportation costs caused by the temporary suspension of the crude-by-rail program; reaching a broader customer base; forecast exchange rates and trends; future opportunities for oil and natural gas development; forecast operating and financial results, including forecast sales prices, costs and cash flows; our ability to satisfy payment obligations as they become due; priorities for and approach to capital investment decisions or capital allocation, including decisions pertaining to new projects and phases; planned capital expenditures, including the amount, timing and funding sources thereof; all statements with respect to our 2021 guidance estimates; expected future production, including the timing, stability or growth thereof; our ability to manage our production well rates in response to pipeline capacity constraints, storage constraints and crude oil price differentials; our ability to take steps to partially mitigate against wider WTI and WCS price differentials; our expectation that the general outlook for light crude oil prices will be tied primarily to the supply and demand response to the current uncertain price environment, the impact of oversupply, and global demand impacts amid COVID-19 concerns; our expectation that the WTI-WCS differential in Alberta will remain largely tied to the extent to which supply cuts are sustainable, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, the completion of the Trans Mountain Expansion project, and the level of crude-by-rail activity; our expectation that in 2021 refining market crack spreads will remain weak relative to previous years as a result of significantly reduced refined products demand due to COVID-19; our expectation that our capital investment and near-term cash requirements will be funded through cash from operating activities and prudent use of our balance sheet capacity including draws on our credit and demand facilities, management of our asset portfolio and other corporate and financial opportunities that may be available to us; statements about our debt level as we manage through the low commodity price environment; expected reserves; focus on mid-term strategies to broaden market access for our crude oil production; supporting proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving our crude oil production to market by rail, and assessing options to maximize the value of our crude oil; impact on alignment of transportation and storage commitments and production growth; all statements related to government royalty regimes applicable to Cenovus, which regimes are subject to change; our ability to preserve our financial resilience and various plans and strategies with respect thereto; our priorities, including for 2021; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact; potential impacts of various risks, including those related to commodity prices and climate change; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof, and anticipated impact on the Consolidated Financial Statements; our expectation that any liabilities that may arise out of legal claims associated with the normal course of our operations are not likely to have a material effect on our Consolidated Financial Statements; the availability and repayment of our credit facilities; potential asset sales; expected impacts of the contingent payment to ConocoPhillips; development of a new five-year business plan for the combined company in 2021; statements about new ESG targets and plans to achieve them; future investment, use and development of technology and equipment and associated future outcomes; our ability to access and implement all technology necessary to efficiently and effectively operate our assets and achieve expected future results; planned capital expenditures; and projected growth and projected shareholder return. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

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

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which our forward-looking information is based include, but are not limited to: forecast oil and natural gas, natural gas liquids, condensate and refined products prices, light-heavy crude oil price differentials; our ability to realize the benefits and anticipated cost synergies associated with the combination of

Cenovus and Husky; Cenovus's ability to successfully integrate the business of Husky, including new business activities, assets, operating areas, regulatory jurisdictions, personnel and business partners for Cenovus; the accuracy of any assessments undertaken in connection with the Husky Arrangement and any resulting *pro forma* information; our forecast production volumes are subject to potential further ramp down of production based on business and market conditions; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; the absence of significant adverse changes to legislation and regulations, Indigenous relations, interest rates, foreign exchange rates, competitive conditions and the supply and demand for crude oil and natural gas, NGLs, condensate and refined products; the political, economic and social stability of jurisdictions in which Cenovus operates; the absence of significant disruption of operations, including as a result of harsh weather, natural disaster, accident, civil unrest or other similar events; the prevailing climatic conditions in Cenovus's operating locations; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to our share price and market capitalization over the long term; opportunities to repurchase shares for cancellation at prices acceptable to us; cash flows, cash balances on hand and access to credit and demand facilities being sufficient to fund capital investments; foreign exchange rate risk, including with respect to our US$ debt and refining capital and operating expenses; our ability to reduce our 2021 oil sands production, including without negative impacts to our assets; realization of expected capacity to store within our oil sands reservoirs barrels not yet produced, including that we will be able to time production and sales of our inventory at later dates when demand has increased, pipeline and/or storage capacity has improved and crude oil differentials have narrowed; the WTI-WCS differential in Alberta remains largely tied to the extent to which voluntary economically driven supply cuts are made, the potential start-up of the Enbridge Inc.'s Line 3 Replacement Program, the completion of Trans Mountain Expansion project, and the level of crude-by-rail activity; the ability of our refining capacity, dynamic storage, existing pipeline commitments and financial hedge transactions to partially mitigate a portion of our WCS crude oil volumes against wider differentials; production declines from both associated gas and dry gas, along with rebounding U.S. demand and liquified natural gas exports should tighten North American gas fundamentals further in 2021 and result in stronger prices than 2020 on an annual basis; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; the accuracy of accounting estimates and judgments; future use and development of technology and associated expected future results; our ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; the sufficiency of existing cash balances, internally generated cash flows, existing credit facilities, management of the Corporation's asset portfolio and access to capital markets to fund future development costs and dividends, including any increase thereto; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and within the timelines we expect; the stability of general domestic and global economic, market and business conditions; forecast inflation and other assumptions inherent in Cenovus's 2021 guidance available on cenovus.com and as set out below; expected impacts of the contingent payment to ConocoPhillips; alignment of realized WCS and WCS prices used to calculate the contingent payment to ConocoPhillips; our ability to access and implement all technology and equipment necessary to achieve expected future results and that such results are realized; our ability to implement capital projects or stages thereof in a successful and timely manner; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2021 guidance, as updated January 28, 2021 and available on cenovus.com, assumes: Brent prices of US$49.50/bbl, WTI prices of US$46.50/bbl; WCS of US$32.50/bbl; Differential WTI-WCS of US$14.00/bbl; AECO natural gas prices of $2.50/Mcf; Chicago 3-2-1 crack spread of US$11.00/bbl; and an exchange rate of $0.78 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially from the forward-looking information, include, but are not limited to: the effect of the COVID-19 pandemic on our business, including any related restrictions, containment, and treatment measures taken by varying levels of government in the jurisdictions in which we operate; the success of our new COVID-19 workplace policies and the return of our people to our workplace; our ability to achieve the benefits and anticipated cost synergies anticipated with the Arrangement in a timely manner or at all; the ability of Cenovus and Husky to amalgamate; Cenovus's ability to successfully integrate Husky's business with its own in a timely and cost effective manner or at all; the effects of entering new business activities; unforeseen or undisclosed liabilities associate with the Arrangement; the inaccuracy of any assessments undertaken in connection with the Arrangement and any resulting *pro forma* information; the inaccuracy of any information provided by Husky; our ability to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve expected future results; the effect of Cenovus's increased indebtedness; the effect of new significant shareholder; volatility of and other assumptions regarding commodity prices; the duration of the market downturn; foreign exchange risk, including related to agreements denominated in foreign currencies; our continued liquidity is sufficient to sustain operations through a prolonged market downturn; WTI-WCS differential in Alberta does not remain largely tied to the extent to which voluntary economically driven supply cuts are made, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, the completion of the Trans Mountain Expansion project, and the level of crude-by-rail activity; our ability to achieve lower transportation costs as a result of temporarily suspending the crude-by-rail

program; our ability to realize the expected impacts of our capacity to store within our oil sands reservoirs barrels not yet produced, including possible inability to time production and sales at later dates when pipeline and/or storage capacity and crude oil differentials have improved; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; the accuracy of our share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks, exposure to counterparties and partners, including the ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of our crude-by-rail terminal, including health, safety and environmental risks; our ability to maintain desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans; our ability to utilize tax losses in the future; the accuracy of our reserves, future production and future net revenue estimates; the accuracy of our accounting estimates and judgements; our ability to replace and expand oil and gas reserves; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project developments; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of our assets or goodwill from time to time; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated operations and business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events resulting in operational interruptions, including blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, gaseous leaks, migration of harmful substances, loss of containment, releases or spills, including releases or spills from offshore facilities and shipping vessels at terminals or hubs and as a result of pipeline or other leaks, corrosion, epidemics or pandemics, and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, iceberg incidents, acts of vandalism and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; the cost and availability of equipment necessary to our operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and Cenovus's reputation, social license to operate and litigation related thereto; unexpected cost increases or technical difficulties in operating, constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and equipment and its application to our business, including potential cyberattacks; geo-political and other risks associated with our international operations; risks associated with climate change and our assumptions relating thereto; the timing and the costs of well and pipeline construction; our ability to access markets and to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system or storage capacity; availability of, and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified leadership and personnel, and equipment in a timely and cost efficient manner; changes in labour demographics and relationships, including with any unionized workforces; unexpected abandonment and reclamation costs; changes in the regulatory frameworks, permits and approvals in any of the locations in which we operate or to any of the infrastructure upon which we rely; government actions or regulatory initiatives to curtail energy operations or pursue broader climate change agendas; changes to regulatory approval processes and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our Consolidated Financial Statements; changes in general economic, market and business conditions; the impact of production agreements among OPEC and non-OPEC members; the political, social and economic conditions in the jurisdictions in which we operate or supply; the status of our relationships with the communities in which we operate, including with Indigenous communicates; the occurrence of unexpected events such as protests, pandemics, war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of our material risk factors, see Risk Management and Risk Factors in this MD&A, and to the risk factors described in other documents Cenovus files from time to time with securities regulatory authorities in Canada, available on SEDAR at sedar.com, and with the U.S. Securities and Exchange Commission on EDGAR at sec.gov, and on the Corporation's website at cenovus.com. Additional information concerning Husky's business and assets as of December 31, 2020 may be found in the Husky AIF and this MD&A, each of which is filed and available on SEDAR under Husky's profile at sedar.com.

Information on or connected to Cenovus's at website cenovus.com or Husky's website at huskyenergy.com does not form part of this MD&A unless expressly incorporated by reference herein.

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	Bcf	billion cubic feet
BOE	barrel of oil equivalent	MMBtu	million British thermal units
MMBOE	million barrel of oil equivalent	GJ	gigajoule
WTI	West Texas Intermediate	AECO	Alberta Energy Company
WCS	Western Canadian Select	NYMEX	New York Mercantile Exchange
CDB	Christina Dilbit Blend		
MSW	Mixed Sweet Blend		
WTS	West Texas Sour		

DEFINITIONS

Scope 1 emissions are direct emissions from owned or operated facilities. Cenovus accounts for emissions on a gross operatorship basis. This includes fuel combustion, venting, flaring and fugitive emissions. It does not include emissions from the 50 percent non-operated ownership in the Company's refineries or emissions from non-operated Conventional assets.

Scope 2 emissions are indirect emissions from the generation of purchased energy for the Company's operated facilities. For Cenovus, this is limited to electricity imports.

NETBACK RECONCILIATIONS

The following tables provide a reconciliation of the items comprising Netbacks to Operating Margin found in our Consolidated Financial Statements.

Total Production

Upstream Financial Results

Year Ended December 31, 2020 ($ millions)	Per Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands [1]	Conventional [1] [2]	Total Upstream	Condensate	Inventory	Internal Usage [3]	Other	Total Upstream
Gross Sales	7,514	635	8,149	(3,452)	-	(295)	(58)	4,344
Royalties	324	40	364	-	6	-	-	370
Transportation and Blending	4,399	81	4,480	(3,452)	285	-	-	1,313
Operating	1,094	318	1,412	-	25	(295)	(33)	1,109
Inventory Write-Down (Reversal)	316	-	316		(316)			-
Netback	1,381	196	1,577	-	-	-	(25)	1,552
(Gain) Loss on Risk Management	268	-	268	-	-	-	-	268
Operating Margin	1,113	196	1,309	-	-	-	(25)	1,284

Year Ended December 31, 2019 ($ millions)	Per Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands [1]	Conventional [1] [2]	Total Upstream	Condensate	Inventory	Internal Usage [3]	Other	Total Upstream
Gross Sales	10,838	691	11,529	(4,021)	-	(222)	(64)	7,222
Royalties	1,143	30	1,173	-	-	-	1	1,174
Transportation and Blending	5,152	82	5,234	(4,021)	-	-	1	1,214
Operating	1,039	337	1,376	-	-	(222)	(33)	1,121
Netback	3,504	242	3,746	-	-	-	(33)	3,713
(Gain) Loss on Risk Management	23	-	23	-	-	-	-	23
Operating Margin	3,481	242	3,723	-	-	-	(33)	3,690

Year Ended December 31, 2018 ($ millions) [4]	Per Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands[1]	Conventional[1] [2]	Continuing Operations	Condensate	Inventory	Internal Usage[3]	Other	Continuing Operations
Gross Sales	10,026	904	10,930	(4,993)	-	(179)	(69)	5,689
Royalties	473	73	546	-	-	-	-	546
Transportation and Blending	5,879	90	5,969	(4,993)	-	-	(4)	972
Operating	1,037	403	1,440	-	-	(179)	(37)	1,224
Netback	2,637	338	2,975	-	-	-	(28)	2,947
(Gain) Loss on Risk Management	1,551	26	1,577	-	-	-	-	1,577
Operating Margin	1,086	312	1,398	-	-	-	(28)	1,370

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) This segment was previously referred to as the Deep Basin segment.
(3) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.
(4) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Three Months Ended December 31, 2020 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands [5]	Conventional [5] [6]	Total Upstream	Condensate	Inventory	Internal Usage [7]	Other	Total Upstream
Gross Sales	2,227	184	2,411	(853)	-	(92)	(17)	1,449
Royalties	131	12	143	-	-	-	-	143
Transportation and Blending	1,131	18	1,149	(853)	-	-	-	296
Operating	309	72	381	-	-	(92)	(10)	279
Inventory Write-Down (Reversal)	-	-	-	-	-	-	-	-
Netback	656	82	738	-	-	-	(7)	731
(Gain) Loss on Risk Management	40	-	40	-	-	-	-	40
Operating Margin	616	82	698	-	-	-	(7)	691

(5) Found in Note 1 of the interim Consolidated Financial Statements.
(6) This segment was previously referred to as the Deep Basin segment.
(7) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.

Three Months Ended December 31, 2019 ($ millions)	Per Interim Consolidated Financial Statements: Oil Sands [1]	Conventional [1] [2]	Total Upstream	Adjustments: Condensate	Inventory	Internal Usage [3]	Other	Basis of Netback Calculation: Total Upstream
Gross Sales	2,659	190	2,849	(1,060)	-	(82)	(13)	1,694
Royalties	316	9	325	-	-	-	1	326
Transportation and Blending	1,416	20	1,436	(1,060)	-	-	1	377
Operating	268	80	348	-	-	(82)	(6)	260
Netback	659	81	740	-	-	-	(9)	731
(Gain) Loss on Risk Management	(15)	-	(15)	-	-	-	-	(15)
Operating Margin	674	81	755	-	-	-	(9)	746

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) This segment was previously referred to as the Deep Basin segment.
(3) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.

Oil Sands

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Consolidated Financial Statements [4]: Total Oil Sands
Gross Sales	1,859	2,194	4,053	-	3,452	-	9	7,514
Royalties	95	235	330	-	-	(6)	-	324
Transportation and Blending	667	565	1,232	-	3,452	(285)	-	4,399
Operating	558	551	1,109	-	-	(25)	10	1,094
Inventory Write-Down (Reversal)	-	-	-			316		316
Netback	539	843	1,382	-	-	-	(1)	1,381
(Gain) Loss on Risk Management	111	157	268	-	-	-	-	268
Operating Margin	428	686	1,114	-	-	-	(1)	1,113

Year Ended December 31, 2019 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Consolidated Financial Statements [4]: Total Oil Sands
Gross Sales	3,295	3,511	6,806	-	4,021	-	11	10,838
Royalties	486	650	1,136	-	-	-	7	1,143
Transportation and Blending	674	458	1,132	-	4,021	-	(1)	5,152
Operating	526	505	1,031	-	-	-	8	1,039
Netback	1,609	1,898	3,507	-	-	-	(3)	3,504
(Gain) Loss on Risk Management	10	13	23	-	-	-	-	23
Operating Margin	1,599	1,885	3,484	-	-	-	(3)	3,481

Year Ended December 31, 2018 ($ millions) [5]	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Consolidated Financial Statements [4]: Total Oil Sands
Gross Sales	2,531	2,489	5,020	1	4,993	-	12	10,026
Royalties	371	102	473	-	-	-	-	473
Transportation and Blending	495	391	886	-	4,993	-	-	5,879
Operating	532	492	1,024	2	-	-	11	1,037
Netback	1,133	1,504	2,637	(1)	-	-	1	2,637
(Gain) Loss on Risk Management	683	868	1,551	-	-	-	-	1,551
Operating Margin	450	636	1,086	(1)	-	-	1	1,086

(4) Found in Note 1 of the Consolidated Financial Statements.
(5) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Three Months Ended December 31, 2020 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements [1]: Total Oil Sands
Gross Sales	615	756	1,371	-	853	-	3	2,227
Royalties	28	103	131	-	-	-	-	131
Transportation and Blending	144	134	278	-	853	-	-	1,131
Operating	154	152	306	-	-	-	3	309
Inventory Write-Down (Reversal)	-	-	-	-	-	-	-	-
Netback	289	367	656	-	-	-	-	656
(Gain) Loss on Risk Management	15	25	40	-	-	-	-	40
Operating Margin	274	342	616	-	-	-	-	616

(1) Found in Note 1 of the interim Consolidated Financial Statements.

Three Months Ended December 31, 2019 ($ millions)	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements (1)
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	731	866	1,597	-	1,060	-	2	2,659
Royalties	130	179	309	-	-	-	7	316
Transportation and Blending	207	150	357	-	1,060	-	(1)	1,416
Operating	132	136	268	-	-	-	-	268
Netback	262	401	663	-	-	-	(4)	659
(Gain) Loss on Risk Management	(5)	(10)	(15)	-	-	-	-	(15)
Operating Margin	267	411	678	-	-	-	(4)	674

(1) Found in Note 1 of the interim Consolidated Financial Statements.

Conventional (2)

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation	Adjustments	Per Consolidated Financial Statements(3)
	Total	Other(4)	Total Conventional
Gross Sales	586	49	635
Royalties	40	-	40
Transportation and Blending	81	-	81
Operating	295	23	318
Netback	170	26	196
(Gain) Loss on Risk Management	-	-	-
Operating Margin	170	26	196

Year Ended December 31, 2019 ($ millions)	Basis of Netback Calculation	Adjustments	Per Consolidated Financial Statements(3)
	Total	Other(4)	Total Conventional
Gross Sales	638	53	691
Royalties	30	-	30
Transportation and Blending	82	-	82
Operating	312	25	337
Netback	214	28	242
(Gain) Loss on Risk Management	-	-	-
Operating Margin	214	28	242

Year Ended December 31, 2018 ($ millions) (5)	Basis of Netback Calculation	Adjustments	Per Consolidated Financial Statements(3)
	Total	Other(4)	Total Conventional
Gross Sales	847	57	904
Royalties	73	-	73
Transportation and Blending	86	4	90
Operating	377	26	403
Netback	311	27	338
Operating Margin	285	27	312

(2) This segment was previously referred to as the Deep Basin segment.
(3) Found in Note 1 of the Consolidated Financial Statements.
(4) Reflects operating margin from processing facility.
(5) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Three Months Ended December 31, 2020 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements(1)
	Total	Other(2)	Total Conventional
Gross Sales	170	14	184
Royalties	12	-	12
Transportation and Blending	18	-	18
Operating	65	7	72
Netback	75	7	82
(Gain) Loss on Risk Management	-	-	-
Operating Margin	75	7	82

Three Months Ended December 31, 2019 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements(1)
	Total	Other(2)	Total Conventional
Gross Sales	179	11	190
Royalties	9	-	9
Transportation and Blending	20	-	20
Operating	74	6	80
Netback	76	5	81
(Gain) Loss on Risk Management	-	-	-
Operating Margin	76	5	81

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Reflects operating margin from processing facility.

The following table provides the sales volumes used to calculate Netback.

Sales Volumes

(barrels per day, unless otherwise stated)	Three Months Ended December 31, 2020	Three Months Ended December 31, 2019	Year Ended December 31 2020	Year Ended December 31 2019	Year Ended December 31 2018
Oil Sands					
Foster Creek	**161,108**	153,797	**164,906**	157,770	162,685
Christina Lake	**220,676**	207,399	**221,675**	188,910	204,016
Total Oil Sands Crude Oil	**381,784**	361,196	**386,581**	346,680	366,701
Conventional (3)					
Total Liquids	**24,543**	26,197	**26,646**	26,673	32,454
Natural Gas (MMcf per day)	**369**	403	**379**	424	527
Total Conventional (BOE per day)	**86,123**	93,317	**89,821**	97,423	120,258
Less: Internal Consumption (4) (MMcf per day)	**(344)**	(336)	**(336)**	(320)	(306)
Sales From Continuing Operations (4) (BOE per day)	**410,864**	398,457	**420,456**	390,813	436,163

(3) This segment was previously referred to as the Deep Basin segment.
(4) Less natural gas volumes used for internal consumption by the Oil Sands segment

Exhibit 99.3



Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2020

(Canadian Dollars)

CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2020

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REPORT OF MANAGEMENT

Management's Responsibility for the Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of five independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation and the United States *Sarbanes – Oxley Act of 2002* and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee met with Management and the independent auditors on at least a quarterly basis to review the interim Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors prior to their public release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

Management's Assessment of Internal Control Over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2020. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that internal control over financial reporting was effective as at December 31, 2020.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2020, as stated in their Report of Independent Registered Public Accounting Firm dated February 8, 2021. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Alexander J. Pourbaix

Alexander J. Pourbaix
President &
Chief Executive Officer
Cenovus Energy Inc.

/s/ Jeffrey R. Hart

Jeffrey R. Hart
Executive Vice-President &
Chief Financial Officer
Cenovus Energy Inc.

February 8, 2021



REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Cenovus Energy Inc.

Opinions on the Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of Cenovus Energy Inc. and its subsidiaries (together, the "Company") as of December 31, 2020 and 2019, and the related consolidated statements of earnings (loss), comprehensive income (loss), shareholders' equity and cash flows for each of the three years in the period ended December 31, 2020, including the related notes (collectively referred to as the "Consolidated Financial Statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control – Integrated Framework (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 3 to the Consolidated Financial Statements, the Company changed the manner in which it accounts for leases as of January 1, 2019 due to the adoption of IFRS 16, Leases.

Basis for Opinions

The Company's Management is responsible for these Consolidated Financial Statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Company's Consolidated Financial Statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the Consolidated Financial Statements included performing procedures to assess the risks of material misstatement of the Consolidated Financial Statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the Consolidated Financial Statements. Our audits also included evaluating the accounting principles used and significant estimates made by Management, as well as evaluating the overall presentation of the Consolidated Financial Statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.



Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the Consolidated Financial Statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the Consolidated Financial Statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the Consolidated Financial Statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Impact of Reserves and Resource Estimates on the Recoverable Amounts of Property, Plant and Equipment ("PP&E") and any Allocated Goodwill (the "recoverable amounts") of the Oil Sands and Conventional Cash Generating Units ("CGUs") and on Depreciation, Depletion and Amortization ("DD&A") Expense for the Oil Sands and Conventional Segments

As described in Notes 1, 3, 4, 10, 18 and 21 to the Consolidated Financial Statements, Management assesses its CGUs for indicators of impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount of a CGU, which is net of accumulated DD&A and net impairment losses, may exceed its recoverable amount. Goodwill is tested for impairment at least annually. Management calculates depletion on the costs accumulated within each area using the unit-of-production method based on estimated proved reserves. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves. As at December 31, 2020, the Company had $19,748 million and $1,758 million in Oil Sands and Conventional PP&E assets net of accumulated DD&A and net impairment losses, respectively. Goodwill related to the Oil Sands segment amounted to $2,272 million as at December 31, 2020. In aggregate, the Company recognized $2,564 million of DD&A expense for the Oil Sands and Conventional segments, which included impairment of $555 million for the Conventional CGUs, for the year ended December 31, 2020. Management determined the recoverable amounts of the Oil Sands and Conventional CGUs based on their fair value less costs of disposal using discounted after-tax cash flows from reserves and resources. These fair value assessments required the use of significant estimates and judgments by Management related to forward commodity prices, expected production volumes, quantity of reserves and resources, royalty payments, and future development and operating expenses as well as estimates over discount rates. Management's estimates of reserves and resources, as applicable, used for both the determination of the recoverable amounts of the Oil Sands and Conventional CGUs and the calculation of DD&A expense for the Oil Sands and Conventional segments have been developed by Management's specialists, specifically independent qualified reserve evaluators.

The principal considerations for our determination that performing procedures relating to the impact of reserves and resource estimates on the recoverable amounts of the Oil Sands and Conventional CGUs and on DD&A expense for the Oil Sands and Conventional segments is a critical audit matter are (i) the significant amount of judgment required by Management, including the use of Management's specialists, when developing the estimates of reserves and resources and the recoverable amounts; (ii) there was a high degree of auditor judgment, subjectivity, and effort in performing procedures relating to the significant assumptions used in developing these estimates including forward commodity prices, expected production volumes, quantity of reserves and resources, future development and operating expenses, as well as discount rates; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.



Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the Consolidated Financial Statements. These procedures included testing the effectiveness of controls relating to Management's estimates of reserves and resources, the determination of the recoverable amounts of the Oil Sands and Conventional CGUs and the calculation of DD&A expense for the Oil Sands and Conventional segments. These procedures also included, among others, testing Management's process for determining the recoverable amounts of the Oil Sands and Conventional CGUs and DD&A expense for the Oil Sands and Conventional segments, which included (i) evaluating the appropriateness of the methods used by Management in making these estimates; (ii) testing the completeness and accuracy of underlying data used in Management's model; (iii) assessing the reasonability of the assumptions used by Management, including forward commodity prices, expected production volumes, quantity of reserves and resources, as well as future development and operating expenses; and (iv) testing the unit-of-production rates used to calculate DD&A expense. The work of Management's specialists was used in performing the procedures to evaluate the reasonableness of the quantity of reserves and resources used to determine the recoverable amounts of the Oil Sands and Conventional CGUs and DD&A expense for the Oil Sands and Conventional segments, as applicable. As a basis for using this work, the specialists' qualifications were understood, and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of data used by the specialists and an evaluation of the specialists' findings. Evaluating the assumptions used by Management's specialists also involved assessing whether the assumptions used were reasonable considering the current and past performance of the Company, consistency with industry pricing forecasts and consistency with evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were also used to assist in evaluating the reasonableness of the recoverability calculations, including the discount rate used within the models.

Impairment Assessment of PP&E for the Wood River and Borger CGUs within the Refining and Marketing Segment

As described in Notes 1, 3, 4, 10 and 18 to the Consolidated Financial Statements, Management assesses its CGUs for indicators of impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount of a CGU, which is net of accumulated DD&A and net impairment losses, may exceed its recoverable amount. As at December 31, 2020, the Company had $3,476 million of PP&E assets net of accumulated DD&A and net impairment losses relating to refining equipment. For the year ended December 31, 2020, the carrying amount of the Borger CGU was determined to be greater than the recoverable amount and an impairment charge of $450 million was recorded as additional DD&A in the Refining and Marketing segment. No impairment of the Wood River CGU was identified by Management. Management determined the recoverable amounts of PP&E for the Wood River and Borger CGUs based on their fair value less costs of disposal using discounted after-tax cash flows requiring the use of significant estimates and judgments by Management related to forward crude oil prices, forward crack spreads, future capital expenditures, operating expenses, terminal values and the discount rates.

The principal considerations for our determination that performing procedures relating to the impairment assessment of PP&E for the Wood River and Borger CGUs within the Refining and Marketing segment is a critical audit matter are (i) the significant amount of judgment required by Management when developing the recoverable amounts of the Wood River and Borger CGUs; (ii) there was a high degree of auditor judgment, subjectivity, and effort in performing procedures relating to the significant assumptions used in developing these estimates including forward crude oil prices, forward crack spreads, future capital expenditures, operating expenses and terminal values, as well as the discount rate applied; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.



Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the Consolidated Financial Statements. These procedures included testing the effectiveness of controls relating to Management's determination of the recoverable amounts of the Wood River and Borger CGU's. These procedures also included, among others, testing Management's process for determining the recoverable amounts of the Wood River and Borger CGU's, which included (i) evaluating the appropriateness of the methods used by Management in making these estimates; (ii) testing the completeness and accuracy of underlying data used in these models; and (iii) assessing the reasonability of the assumptions used by Management, including forward crude oil prices, forward crack spreads, future capital expenditures and operating expenses. Evaluating the assumptions used by Management involved assessing whether the assumptions used were reasonable considering the current and past performance of the Company, consistency with industry pricing forecasts and consistency with evidence obtained in other areas of the audit. Professionals with specialized skill and knowledge were used to assist in evaluating the overall reasonableness of the recoverability calculations, including terminal values and the discount rates used within the models.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta, Canada

February 8, 2021

We have served as the Company's auditor since 2008.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

For the years ended December 31,
($ millions, except per share amounts)

	Notes	**2020**	2019	2018
Revenues	1			
Gross Sales		**13,591**	21,353	21,389
Less: Royalties		**364**	1,173	546
		13,227	20,180	20,843
Expenses	1			
Purchased Product		**5,119**	8,378	8,684
Transportation and Blending		**4,444**	5,184	5,942
Operating		**1,930**	2,088	2,184
Inventory Write-Down (Reversal)	16	**555**	49	60
(Gain) Loss on Risk Management	35	**308**	156	305
Depreciation, Depletion and Amortization	10,17,18,19	**3,464**	2,249	2,131
Exploration Expense	10,17	**91**	82	2,123
General and Administrative	5	**292**	331	1,020
Finance Costs	6	**536**	511	627
Interest Income		**(9)**	(12)	(19)
Transaction Costs	39	**29**	-	-
Foreign Exchange (Gain) Loss, Net	7	**(181)**	(404)	854
Re-measurement of Contingent Payment	26	**(80)**	164	50
(Gain) Loss on Divestiture of Assets	8	**(81)**	(2)	795
Other (Income) Loss, Net	9	**40**	9	13
Earnings (Loss) From Continuing Operations Before Income Tax		**(3,230)**	1,397	(3,926)
Income Tax Expense (Recovery)	12	**(851)**	(797)	(1,010)
Net Earnings (Loss) From Continuing Operations		**(2,379)**	2,194	(2,916)
Net Earnings (Loss) From Discontinued Operations	11	**-**	-	247
Net Earnings (Loss)		**(2,379)**	2,194	(2,669)
Basic and Diluted Earnings (Loss) Per Share ($)	13			
Continuing Operations		**(1.94)**	1.78	(2.37)
Discontinued Operations		**-**	-	0.20
Net Earnings (Loss) Per Share		**(1.94)**	1.78	(2.17)

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31,
($ millions)

	Notes	**2020**	2019	2018
Net Earnings (Loss)		**(2,379)**	2,194	(2,669)
Other Comprehensive Income (Loss), Net of Tax	31			
Items That Will Not be Reclassified to Profit or Loss:				
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**(8)**	5	(3)
Change in the Fair Value of Equity Instruments at FVOCI (1)		**-**	12	1
Items That May be Reclassified to Profit or Loss:				
Foreign Currency Translation Adjustment		**(44)**	(228)	397
Total Other Comprehensive Income (Loss), Net of Tax		**(52)**	(211)	395
Comprehensive Income (Loss)		**(2,431)**	1,983	(2,274)

(1) Fair value through other comprehensive income (loss) ("FVOCI").

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31,
($ millions)

	Notes	**2020**	2019
Assets			
Current Assets			
Cash and Cash Equivalents	14	**378**	186
Accounts Receivable and Accrued Revenues	15	**1,488**	1,556
Income Tax Receivable		**21**	10
Inventories	16	**1,089**	1,532
Total Current Assets		**2,976**	3,284
Exploration and Evaluation Assets	1,17	**623**	787
Property, Plant and Equipment, Net	1,18	**25,411**	27,834
Right-of-Use Assets, Net	1,19	**1,139**	1,325
Other Assets	20	**313**	211
Deferred Income Taxes	12	**36**	-
Goodwill	1,21	**2,272**	2,272
Total Assets		**32,770**	35,713
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	22	**2,018**	2,229
Short-Term Borrowings	23	**121**	-
Lease Liabilities	25	**184**	196
Contingent Payment	26	**36**	79
Income Tax Payable		**-**	17
Total Current Liabilities		**2,359**	2,521
Long-Term Debt	24	**7,441**	6,699
Lease Liabilities	25	**1,573**	1,720
Contingent Payment	26	**27**	64
Decommissioning Liabilities	27	**1,248**	1,235
Other Liabilities	28	**181**	241
Deferred Income Taxes	12	**3,234**	4,032
Total Liabilities		**16,063**	16,512
Shareholders' Equity		**16,707**	19,201
Total Liabilities and Shareholders' Equity		**32,770**	35,713
Commitments and Contingencies	38		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board of Directors

/s/ Keith A. MacPhail

Keith A. MacPhail
Director
Cenovus Energy Inc.

/s/ Claude Mongeau

Claude Mongeau
Director
Cenovus Energy Inc.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)

	Share Capital	Paid in Surplus	Retained Earnings	AOCI (1)	**Total**
	(Note 30)	(Note 30)		(Note 31)	
As at December 31, 2017	11,040	4,361	3,937	643	19,981
Net Earnings (Loss)	-	-	(2,669)	-	(2,669)
Other Comprehensive Income (Loss)	-	-	-	395	395
Total Comprehensive Income (Loss)	-	-	(2,669)	395	(2,274)
Stock-Based Compensation Expense	-	6	-	-	6
Dividends on Common Shares	-	-	(245)	-	(245)
As at December 31, 2018	11,040	4,367	1,023	1,038	17,468
Net Earnings (Loss)	-	-	2,194	-	2,194
Other Comprehensive Income (Loss)	-	-	-	(211)	(211)
Total Comprehensive Income (Loss)	-	-	2,194	(211)	1,983
Stock-Based Compensation Expense	-	10	-	-	10
Dividends on Common Shares	-	-	(260)	-	(260)
As at December 31, 2019	11,040	4,377	2,957	827	19,201
Net Earnings (Loss)	-	-	(2,379)	-	(2,379)
Other Comprehensive Income (Loss)	-	-	-	(52)	(52)
Total Comprehensive Income (Loss)	-	-	(2,379)	(52)	(2,431)
Stock-Based Compensation Expense	-	14	-	-	14
Dividends on Common Shares	-	-	(77)	-	(77)
As at December 31, 2020	**11,040**	**4,391**	**501**	**775**	**16,707**

(1) Accumulated other comprehensive income (loss) ("AOCI").

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,
($ millions)

	Notes	2020	2019	2018
Operating Activities				
Net Earnings (Loss)		**(2,379)**	2,194	(2,669)
Depreciation, Depletion and Amortization	10,17,18,19	**3,464**	2,249	2,131
Exploration Expense	10,17	**91**	82	2,123
Inventory Write-Down (Reversal)	16	**555**	49	60
Deferred Income Tax Expense (Recovery)	12	**(838)**	(814)	(794)
Unrealized (Gain) Loss on Risk Management	35	**56**	149	(1,249)
Unrealized Foreign Exchange (Gain) Loss	7	**(131)**	(827)	649
Re-measurement of Contingent Payment	26	**(80)**	164	50
(Gain) Loss on Discontinuance	11	**-**	-	(301)
(Gain) Loss on Divestiture of Assets	8	**(81)**	(2)	795
Unwinding of Discount on Decommissioning Liabilities	27	**57**	58	63
Realized Inventory Write-Down		**(572)**	(71)	(13)
Realized Foreign Exchange (Gain) Loss on Non-Operating Items		**(33)**	401	206
Other		**38**	70	670
Net Change in Other Assets and Liabilities		**(72)**	(84)	(72)
Net Change in Non-Cash Working Capital		**198**	(333)	505
Cash From (Used in) Operating Activities		**273**	3,285	2,154
Investing Activities				
Capital Expenditures – Exploration and Evaluation Assets	17	**(48)**	(73)	(55)
Capital Expenditures – Property, Plant and Equipment	18	**(811)**	(1,110)	(1,322)
Proceeds From Divestitures	8,11	**38**	1	1,050
Net Change in Investments and Other		**(4)**	(133)	9
Net Change in Non-Cash Working Capital		**(38)**	(117)	(295)
Cash From (Used in) Investing Activities		**(863)**	(1,432)	(613)
Net Cash Provided (Used) Before Financing Activities		**(590)**	1,853	1,541
Financing Activities	37			
Issuance (Repayment) of Short-Term Borrowings		**117**	-	-
Issuance of Long-Term Debt		**1,326**	-	-
Repayment of Long-Term Debt		**(112)**	(2,279)	(1,144)
Net Issuance (Repayment) of Revolving Long-Term Debt		**(220)**	276	(20)
Principal Repayment of Leases		**(197)**	(150)	-
Dividends Paid on Common Shares	13	**(77)**	(260)	(245)
Other		**-**	-	(1)
Cash From (Used in) Financing Activities		**837**	(2,413)	(1,410)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(55)**	(35)	40
Increase (Decrease) in Cash and Cash Equivalents		**192**	(595)	171
Cash and Cash Equivalents, Beginning of Year		**186**	781	610
Cash and Cash Equivalents, End of Year		**378**	186	781

See accompanying Notes to Consolidated Financial Statements.

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. and its subsidiaries, (together "Cenovus" or the "Company") are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and refining operations in the United States ("U.S.").

Cenovus is incorporated under the "*Canada Business Corporations Act*" and its shares are listed on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at 4100, 225 6 Avenue S.W., Calgary, Alberta, Canada, T2P 1N2. Information on the Company's basis of preparation for these Consolidated Financial Statements is found in Note 2.

On October 25, 2020, Cenovus announced that it had entered into a definitive agreement to combine with Husky Energy Inc. ("Husky"). The transaction was accomplished through a plan of arrangement (the "Arrangement") pursuant to which Cenovus acquired all the issued and outstanding common shares of Husky in exchange for common shares and common share purchase warrants of Cenovus. In addition, all of the issued and outstanding Husky preferred shares were exchanged for Cenovus preferred shares with substantially identical terms. The Arrangement closed on January 1, 2021 (see Note 39).

The Arrangement will combine oil sands and heavy oil assets with extensive transportation, storage and logistics and downstream infrastructure, creating opportunities to optimize the margin captured across the heavy oil value chain. The combined company will be largely integrated reducing exposure to Alberta heavy oil price differentials while maintaining exposure to global commodity prices.

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Cenovus's chief operating decision makers. The Company evaluates the financial performance of its operating segments primarily based on operating margin. The Company's reportable segments at December 31, 2020 are:

- **Oil Sands**, which includes the development and production of bitumen in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as other projects in the early stages of development.
- **Conventional**, which includes assets rich in NGLs and natural gas within the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas in Alberta and British Columbia and the exploration for heavy oil in Marten Hills area. The assets include interests in numerous natural gas processing facilities. The Company renamed its Deep Basin segment to Conventional in 2020 and its new resource play, Marten Hills, was reclassified from the Oil Sands segment to the Conventional segment. Comparative periods have been reclassified. On December 2, 2020, the Company completed the sale of its Marten Hills assets (see Note 8).
- **Refining and Marketing**, which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification. The marketing of crude oil and natural gas sourced from Canada, including physical product sales that settle in the U.S., is considered to be undertaken by a Canadian business. U.S. sourced crude oil and natural gas purchases and sales are attributed to the U.S.
- **Corporate and Eliminations**, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Company's rail terminal, crude oil production used as feedstock by the Refining and Marketing segment, and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices. The Corporate and Eliminations segment is attributed to Canada, with the exception of unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

The following tabular financial information presents the segmented information first by segment, then by product and geographic location.

A) Results of Operations – Segment and Operational Information

	Oil Sands			Conventional			Refining and Marketing		
For the years ended December 31,	**2020**	2019	2018	**2020**	2019	2018	**2020**	2019	2018
Revenues									
Gross Sales	**7,514**	10,838	10,026	**635**	691	904	**6,051**	10,513	11,183
Less: Royalties	**324**	1,143	473	**40**	30	73	**-**	-	-
	7,190	9,695	9,553	**595**	661	831	**6,051**	10,513	11,183
Expenses									
Purchased Product	**-**	-	-	**-**	-	-	**5,397**	8,795	9,201
Transportation and Blending	**4,399**	5,152	5,879	**81**	82	90	**-**	-	-
Operating	**1,094**	1,039	1,037	**318**	337	403	**824**	948	927
Inventory Write-Down (Reversal)	**316**	-	-	**-**	-	-	**239**	49	60
(Gain) Loss on Risk Management	**268**	23	1,551	**-**	-	26	**(21)**	(16)	(1)
Operating Margin	**1,113**	3,481	1,086	**196**	242	312	**(388)**	737	996
Depreciation, Depletion and Amortization	**1,684**	1,543	1,439	**880**	319	412	**739**	280	222
Exploration Expense	**9**	18	6	**82**	64	2,117	**-**	-	-
Segment Income (Loss)	**(580)**	1,920	(359)	**(766)**	(141)	(2,217)	**(1,127)**	457	774

	Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2020**	2019	2018	**2020**	2019	2018
Revenues						
Gross Sales	**(609)**	(689)	(724)	**13,591**	21,353	21,389
Less: Royalties	**-**	-	-	**364**	1,173	546
	(609)	(689)	(724)	**13,227**	20,180	20,843
Expenses						
Purchased Product	**(278)**	(417)	(517)	**5,119**	8,378	8,684
Transportation and Blending	**(36)**	(50)	(27)	**4,444**	5,184	5,942
Operating	**(306)**	(236)	(183)	**1,930**	2,088	2,184
Inventory Write-Down (Reversal)	**-**	-	-	**555**	49	60
(Gain) Loss on Risk Management	**61**	149	(1,271)	**308**	156	305
Depreciation, Depletion and Amortization	**161**	107	58	**3,464**	2,249	2,131
Exploration Expense	**-**	-	-	**91**	82	2,123
Segment Income (Loss)	**(211)**	(242)	1,216	**(2,684)**	1,994	(586)
General and Administrative	**292**	331	1,020	**292**	331	1,020
Finance Costs	**536**	511	627	**536**	511	627
Interest Income	**(9)**	(12)	(19)	**(9)**	(12)	(19)
Transaction Costs	**29**	-	-	**29**	-	-
Foreign Exchange (Gain) Loss, Net	**(181)**	(404)	854	**(181)**	(404)	854
Re-measurement of Contingent Payment	**(80)**	164	50	**(80)**	164	50
(Gain) Loss on Divestiture of Assets	**(81)**	(2)	795	**(81)**	(2)	795
Other (Income) Loss, Net	**40**	9	13	**40**	9	13
	546	597	3,340	**546**	597	3,340
Earnings (Loss) From Continuing Operations Before Income Tax				**(3,230)**	1,397	(3,926)
Income Tax Expense (Recovery)				**(851)**	(797)	(1,010)
Net Earnings (Loss) From Continuing Operations				**(2,379)**	2,194	(2,916)

B) Revenues by Product

For the years ended December 31,	2020	2019	2018
Upstream			
Crude Oil	**7,270**	9,790	9,662
NGLs	**142**	202	333
Natural Gas	**315**	299	320
Other	**58**	65	69
Refined Products	**4,734**	8,291	9,032
Market Optimization	**1,317**	2,222	2,151
Corporate and Eliminations	**(609)**	(689)	(724)
Revenues From Continuing Operations	**13,227**	20,180	20,843

C) Geographical Information

	Revenues		
For the years ended December 31,	2020	2019	2018
Canada	**8,399**	11,798	11,694
United States	**4,828**	8,382	9,149
Consolidated	**13,227**	20,180	20,843

	Non-Current Assets (1)	
As at December 31,	2020	2019
Canada	**26,168**	28,336
United States	**3,590**	4,093
Consolidated	**29,758**	32,429

(1) Includes exploration and evaluation ("E&E") assets, property, plant and equipment ("PP&E"), right-of-use ("ROU") assets, other assets and goodwill.

Export Sales

Sales of crude oil, NGLs and natural gas produced or purchased in Canada that have been delivered to customers outside of Canada were $2,639 million (2019 – $4,002 million; 2018 – $2,500 million).

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, NGLs, natural gas and refined products for the year ended December 31, 2020, Cenovus had three customers (2019 – two; 2018 – three) that individually accounted for more than 10 percent of its consolidated gross sales. Sales to these customers, recognized as major international energy companies with investment grade credit ratings, were approximately $4,323 million, $1,834 million and $1,472 million, respectively (2019 – $6,922 million and $2,316 million; 2018 – $7,840 million, $2,285 million and $2,263 million), which are included in all of the Company's operating segments.

D) Assets by Segment

	E&E Assets (1)		PP&E		ROU Assets	
As at December 31,	2020	2019	2020	2019	2020	2019
Oil Sands	**617**	594	**19,748**	20,924	**623**	768
Conventional	**6**	193	**1,758**	2,433	**3**	3
Refining and Marketing	**-**	-	**3,652**	4,131	**79**	77
Corporate and Eliminations	**-**	-	**253**	346	**434**	477
Consolidated	**623**	787	**25,411**	27,834	**1,139**	1,325

	Goodwill		Total Assets	
As at December 31,	2020	2019	2020	2019
Oil Sands	**2,272**	2,272	**24,656**	26,203
Conventional	**-**	-	**1,953**	2,754
Refining and Marketing	**-**	-	**4,951**	5,688
Corporate and Eliminations	**-**	-	**1,210**	1,068
Consolidated	**2,272**	2,272	**32,770**	35,713

(1) Prior to its sale, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment and the comparative period was reclassified.

E) Capital Expenditures (1)

For the years ended December 31,	2020	2019	2018
Capital Investment (2)			
Oil Sands	**427**	656	870
Conventional	**78**	103	228
Refining and Marketing	**276**	280	208
Corporate and Eliminations	**60**	137	57
	841	1,176	1,363
Acquisition Capital			
Oil Sands	**6**	2	319
Conventional	**12**	7	22
Refining and Marketing	**-**	4	-
Total Capital Expenditures	**859**	1,189	1,704

(1) Includes expenditures on PP&E and E&E assets.
(2) Prior to its sale, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment and the comparative periods were reclassified.

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

These Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC").

These Consolidated Financial Statements have been prepared on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements were approved by the Board of Directors on February 8, 2021.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are entities over which the Company has control. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances, and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company's refining activities are conducted through the joint operation WRB Refining LP ("WRB") and, accordingly, the accounts reflect the Company's share of the assets, liabilities, revenues and expenses.

An associate is an entity for which the Company has significant influence over but does not control or jointly control the investee. Investments in associates are accounted for using the equity method of accounting and are recognized at cost and adjusted thereafter to recognize the Company's share of the investee's profit or loss and other comprehensive income ("OCI").

B) Foreign Currency Translation

Functional and Presentation Currency

The Company's functional and presentation currency is Canadian dollars. The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period-end exchange rates for assets and liabilities, and using average rates over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in OCI as cumulative translation adjustments.

When the Company disposes of an entire interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in OCI related to the foreign operation are recognized in net earnings. When the Company disposes of part of an interest in a foreign operation that continues to be a subsidiary, a proportionate amount of gains and losses accumulated in OCI is allocated between controlling and non-controlling interests.

Transactions and Balances

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period-end date. Any gains or losses are recorded in the Consolidated Statements of Earnings (Loss).

C) Revenue Recognition

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. Cenovus recognizes revenue when it transfers control of the product or service to a customer, which is generally when title passes from the Company to its customer.

Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with services provided as agent are recorded as the services are provided.

Cenovus recognizes revenue from the following major products and services:

- Sale of crude oil, NGLs and natural gas.
- Sale of petroleum and refined products.
- Natural gas processing revenue.
- Marketing and transportation services.
- Fee-for-service hydrocarbon trans-loading services.

The Company satisfies its performance obligations in contracts with customers upon the delivery of crude oil, NGLs, natural gas and petroleum and refined products, which is generally at a point in time. Performance obligations for natural gas processing revenue, marketing, transportation services and trans-loading services are satisfied over time as the service is provided. Cenovus sells its production of crude oil, NGLs, natural gas and petroleum and refined products generally pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period. Revenue associated with natural gas processing, marketing, transportation services and trans-loading services are based, generally on fixed price contracts.

Cenovus's revenue transactions do not contain significant financing components and payments are typically due within 30 days of revenue recognition. The Company does not adjust transaction prices for the effects of a significant financing component when the period between the transfer of the promised goods or services to the customer and payment by the customer is less than one year. The Company does not disclose or quantify information about remaining performance obligations that have an original expected duration of one year or less and it does not have any long-term contracts with unfulfilled performance obligations.

D) Transportation and Blending

The costs associated with the transportation of crude oil, NGLs and natural gas, including the cost of diluent used in blending, are recognized when the product is sold.

E) Exploration Expense

Costs incurred prior to obtaining the legal right to explore (pre-exploration costs) are expensed in the period in which they are incurred as exploration expense.

Costs incurred after the legal right to explore is obtained are initially capitalized. If it is determined that the field/project/area is not technically feasible and commercially viable or if the Company decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense.

F) Employee Benefit Plans

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component and an other post-employment benefit plan ("OPEB").

Pension expense for the defined contribution pension is recorded as the benefits are earned.

The cost of the defined benefit pension and OPEB plans are actuarially determined using the projected unit credit method. The amount recognized in other liabilities on the Consolidated Balance Sheets for the defined benefit pension and OPEB plans is the present value of the defined benefit obligation less the fair value of plan assets. Any surplus resulting from this calculation is limited to the present value of any economic benefits available in the form of refunds from the plans or reductions in future contributions to the plans.

Changes in the defined benefit obligation from service costs, net interest and remeasurements are recognized as follows:

- Service costs, including current service costs, past service costs, gains and losses on curtailments, and settlements, are recorded with pension benefit costs.
- Net interest is calculated by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability measured. Interest expense and interest income on net post-employment benefit liabilities and assets are recorded with pension benefit costs in operating, and general and administrative expenses, as well as PP&E and E&E assets.
- Remeasurements, composed of actuarial gains and losses, the effect of changes to the asset ceiling (excluding interest) and the return on plan assets (excluding interest income), are charged or credited to equity in OCI in the period in which they arise. Remeasurements are not reclassified to net earnings in subsequent periods.

Pension benefit costs are recorded in operating, and general and administrative expenses, as well as PP&E and E&E assets, corresponding to where the associated salaries of the employees rendering the service are recorded.

From time-to-time, the Company may provide certain other long-term incentive benefits to employees. In 2019, a one-time incentive program was introduced whereby a cash award equivalent to the employee's base salary is payable if Cenovus achieves prior to February 12, 2024 a target share price of $20 per share for a period of 20 consecutive trading days on the TSX (the "Plan"). All employees, except for the President & Chief Executive Officer, are eligible and new employees are eligible for a pro-rated award based on start date provided they are employed on the payout date. The obligation related to this Plan is estimated as the probability of the payout being achieved multiplied by the expected payout amount. The obligation is recognized over the greater of (i) the time to earliest payout of February 13, 2022; and (ii) the estimated time until payout is achieved, prior to February 12, 2024 as general and administrative expense.

G) Government Grants

Government grants are recognized when there is reasonable assurance that the grant will be received and all conditions associated with the grant are met. Grants related to assets are recorded as a reduction to the asset's carrying value and are depreciated over the useful life of the asset. Claims under government grant programs related to income are recorded as other income in the period in which eligible expenses were incurred or when the services have been performed.

H) Income Taxes

Income taxes comprise current and deferred taxes. Income taxes are provided for on a non-discounted basis at amounts expected to be paid using the tax rates and laws that have been enacted or substantively enacted at the Consolidated Balance Sheet date.

Cenovus follows the liability method of accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs, except when it relates to items charged or credited directly to equity or OCI, in which case the deferred income tax is also recorded in equity or OCI, respectively.

Deferred income tax is recognized on temporary differences arising from investments in subsidiaries except in the case where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future or when distributions can be made without incurring income taxes.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized. Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction. Deferred income tax assets and liabilities are presented as non-current.

I) Net Earnings per Share Amounts

Basic net earnings per share is computed by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share is calculated giving effect to the potential dilution that would occur if stock options or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price. For those contracts that may be settled in cash or in shares at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

J) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less.

K) Inventories

Product inventories are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis. The cost of inventory includes all costs incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if circumstances which caused it no longer exist and the inventory is still on hand.

L) Exploration and Evaluation Assets

Costs incurred after the legal right to explore an area has been obtained, and before technical feasibility and commercial viability of the field/project/area have been established, are capitalized as E&E assets. These costs include license acquisition, geological and geophysical, drilling, sampling, decommissioning and other directly attributable internal costs. E&E assets are carried forward until technical feasibility and commercial viability of the field/project/area is established or the assets are determined to be impaired or the future economic value has decreased. E&E costs are subject to regular technical, commercial and Management review to confirm the continued intent to develop the resources.

Assets classified as E&E may have sales of crude oil, NGLs or natural gas prior to the reclassification to PP&E. These operating results are recognized in the Consolidated Statements of Earnings (Loss). A depletion charge, recorded as depreciation, depletion and amortization ("DD&A"), is recognized on this production using a unit-of-production method based on estimated proved reserves determined using forward prices and costs and considering any estimated future costs to be incurred in developing the proved reserves. Natural gas reserves are converted on an energy equivalent basis.

Non-producing assets classified as E&E are not depleted.

Once technical feasibility and commercial viability have been established, the carrying value of the E&E asset is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as PP&E.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

M) Property, Plant and Equipment

General

PP&E is stated at cost less accumulated DD&A, and net of any impairment losses. Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

Any gains or losses from the divestiture of PP&E are recognized in net earnings.

Development and Production Assets

Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of crude oil and natural gas properties, as well as any E&E expenditures incurred in finding reserves of crude oil, NGLs or natural gas transferred from E&E assets. Capitalized costs include directly attributable internal costs, decommissioning liabilities and, for qualifying assets, borrowing costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

Costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using forward prices and costs. For the purpose of this calculation, natural gas is converted to crude oil on an energy equivalent basis. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of neither the asset received, nor the asset given up, can be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Other Upstream Assets

Other upstream assets include information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three years. Other upstream assets also include gross overriding royalty interests ("GORRs") in certain oil and gas properties and are depleted using a unit-of-production method.

Refining Assets

The initial acquisition costs of refining PP&E are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use, the associated decommissioning costs and, for qualifying assets, borrowing costs.

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The major components are depreciated as follows:

Land improvements and buildings	25 to 40 years
Office equipment and vehicles	3 to 15 years
Refining equipment	10 to 60 years

The residual value, the method of amortization and the useful life of each component are reviewed annually and adjusted on a prospective basis, if appropriate.

Other Assets

Costs associated with the crude-by-rail terminal, infrastructure, office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three years to 60 years.

The residual value, the method of amortization and the useful lives of the assets are reviewed annually and adjusted on a prospective basis, if appropriate.

N) Impairment of Non-Financial Assets

PP&E, E&E assets and ROU assets are reviewed separately for indicators of impairment quarterly or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Goodwill is tested for impairment at least annually.

If indicators of impairment exist, the recoverable amount of the asset or cash-generating unit ("CGU") is estimated as the greater of value-in-use ("VIU") and fair value less costs of disposal ("FVLCOD"). VIU is estimated as the present value of the future cash flows expected to arise from the continuing use of a CGU or an asset. FVLCOD is the amount that would be realized from the disposition of an asset or CGU in an arm's length transaction between knowledgeable and willing parties. For Cenovus's upstream assets, FVLCOD is based on the discounted after-tax cash flows of reserves and resources using forward prices and costs, consistent with Cenovus's independent qualified reserves evaluators ("IQREs") and may consider an evaluation of comparable asset transactions.

E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. ROU assets may be tested as part of a CGU, as a separate CGU or as an individual asset. Goodwill is allocated to the CGUs to which it contributes to the future cash flows.

If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

Impairment losses on PP&E and ROU assets are recognized in the Consolidated Statements of Earnings (Loss) as additional DD&A and E&E asset impairments or write-downs are recognized as exploration expense.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

O) Leases

The Company adopted IFRS 16, "*Leases*" ("IFRS 16") on January 1, 2019 using the modified retrospective approach; therefore comparative periods were not restated.

Policy Applicable From January 1, 2019

Leases

The Company assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration. The Company allocates the consideration in the contract to each lease component on the basis of their relative stand-alone prices. However, for the leases of storage tanks, the Company has elected not to separate non-lease components.

As Lessee

Leases are recognized as a ROU asset and a corresponding lease liability at the date on which the leased asset is available for use by the Company. Assets and liabilities arising from a lease are initially measured on a present value

basis. Lease liabilities include the net present value of fixed payments, costs to be incurred by the lessee in dismantling, removing and restoring the underlying asset, variable lease payments that are based on an index or a rate, amounts expected to be paid by the lessee under residual value guarantees, the exercise price of purchase options if the lessee is reasonably certain to exercise that option, and payments of penalties for terminating the lease, less any lease incentives receivable. These payments are discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of leases with reasonably similar characteristics.

Lease payments are allocated between the liability and finance costs. The finance cost is charged to net earnings over the lease term.

The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether the Company will exercise a purchase, extension or termination option that is within the control of the Company.

When the lease liability is remeasured, a corresponding adjustment is made to the carrying amount of the ROU asset or is recorded in the Consolidated Statements of Earnings (Loss) if the carrying amount of the ROU asset has been reduced to zero.

The ROU asset is initially measured at cost, which comprises the initial amount of the lease liability any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or site on which it is located less any lease payments made at or before the commencement date.

The ROU asset is depreciated, on a straight-line basis, over the shorter of the estimated useful life of the asset or the lease term. The ROU asset may be adjusted for certain remeasurements of the lease liability and impairment losses.

Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the Consolidated Statements of Earnings (Loss) on a straight-line basis over the lease term.

A lease modification will be accounted for as a separate lease if the modification increases the scope of the lease and if the consideration for the lease increases by an amount commensurate with the stand-alone price for the increase in scope. For a modification that is not a separate lease or where the increase in consideration is not commensurate, at the effective date of the lease modification, the Company will remeasure the lease liability using the Company's incremental borrowing rate, when the rate implicit to the lease is not readily available, with a corresponding adjustment to the ROU asset. A modification that decreases the scope of the lease will be accounted for by decreasing the carrying amount of the ROU asset, and recognizing a gain or loss in net earnings that reflects the proportionate decrease in scope.

As Lessor

As a lessor, the Company assesses at inception whether a lease is a finance or operating lease. Leases where the Company transfers substantially all of the risk and rewards incidental to ownership of the underlying asset are classified as financing leases. Under a finance lease, the Company recognizes a receivable at an amount equal to the net investment in the lease which is the present value of the aggregate of lease payments receivable by the lessor. If substantially all the risks and rewards of ownership of an asset are not transferred the lease is classified as an operating lease. The Company recognizes lease payments received under operating leases as income on a straight-line basis over the lease term as other income.

When the Company is an intermediate lessor, it accounts for its interest in the head lease and the sublease separately. It assesses the lease classification of a sublease with reference to the ROU asset from the head lease not with reference to the underlying assets. If the head lease is a short-term lease to which the Company applies the exemption for lease accounting, the sublease is classified as an operating lease.

Policy Applicable Before January 1, 2019

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. At inception, a leased asset within PP&E and a corresponding lease obligation are recognized. The leased asset is depreciated over the shorter of the estimated useful life of the asset or the lease term.

P) Intangible Assets

Intangible assets acquired separately are initially measured at cost. Following initial recognition, intangible assets are recognized at cost less any accumulated amortization and accumulated impairment losses. Intangible assets with finite lives are amortized over the useful life and assessed for impairment whenever there is an indication that the

intangible asset may be impaired. The amortization expense on intangible assets is recognized in the Consolidated Statements of Earnings (Loss) in the expense category consistent with the function of the intangible asset.

Q) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and non-controlling interest, if any, are recognized and measured at their fair value at the date of acquisition, with the exception of income taxes, stock-based compensation, lease liabilities and ROU assets. Any excess of the purchase price plus any non-controlling interest over the value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

Contingent consideration transferred in a business combination is measured at fair value on the date of acquisition and classified as a financial liability or equity. Contingent consideration classified as a liability is re-measured at fair value at each reporting date, with changes in fair value recognized in net earnings. Payments are classified as cash used in investing activities until the cumulative payments exceed the acquisition date fair value of the liability. Cumulative payments in excess of the acquisition date fair value are classified as cash used in operating activities. Contingent consideration classified as equity are not re-measured and settlements are accounted for within equity.

When a business combination is achieved in stages, the Company re-measures its pre-existing interest at the acquisition date fair value and recognizes the resulting gain or loss, if any, in net earnings.

R) Provisions

General

A provision is recognized if, as a result of a past event, the Company has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Where applicable, provisions are determined by discounting the expected future cash flows at a pre-tax credit-adjusted rate that reflects the current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance cost in the Consolidated Statements of Earnings (Loss).

Decommissioning Liabilities

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, upstream processing facilities, refining facilities and the crude-by-rail terminal. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. A corresponding asset equal to the initial estimate of the liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to expected timing or future decommissioning costs are recognized as a change in the decommissioning liability and the related long-lived asset. The amount capitalized in PP&E is depreciated over the useful life of the related asset.

Actual expenditures incurred are charged against the accumulated liability.

Onerous Contract Provisions

Onerous contract provisions are recognized when the unavoidable costs of meeting the obligation exceed the economic benefit derived from the contract. The provision for onerous contracts is measured at the present value of estimated future cash flows underlying the obligations less any estimated recoveries, discounted at the credit-adjusted risk-free rate. Changes in the underlying assumptions are recognized in the Consolidated Statements of Earnings (Loss).

S) Share Capital

Common shares are classified as equity. Transaction costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any income taxes.

T) Stock-Based Compensation

Cenovus has a number of stock-based compensation plans which include stock options with associated net settlement rights (“NSRs”), performance share units (“PSUs”), restricted share units (“RSUs”), and deferred share units (“DSUs”). Stock-based compensation costs are recorded in general and administrative expense, or E&E assets and PP&E when directly related to exploration or development activities.

Net Settlement Rights

NSRs are accounted for as equity instruments, which are measured at fair value on the grant date using the Black-Scholes-Merton valuation model and are not revalued at each reporting date. The fair value is recognized as stock-

based compensation costs over the vesting period, with a corresponding increase recorded as paid in surplus in Shareholders' Equity. On exercise, the cash consideration received by the Company and the associated paid in surplus are recorded as share capital.

Performance, Restricted and Deferred Share Units

PSUs, RSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as stock-based compensation costs over the vesting period. Fluctuations in the fair values are recognized as stock-based compensation costs in the period they occur.

U) Financial Instruments

The Company's financial assets include cash and cash equivalents, accounts receivable and accrued revenues, risk management assets, net investment in finance leases, investments in the equity of private companies and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, short-term borrowings, lease liabilities, contingent payment, risk management liabilities and long-term debt.

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously.

The Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities.
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly.
- Level 3 inputs are unobservable inputs for the asset or liability.

Classification and Measurement of Financial Assets

The initial classification of a financial asset depends upon the Company's business model for managing its financial assets and the contractual terms of the cash flows. There are three measurement categories into which the Company classified its financial assets:

- Amortized Cost: Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest.
- FVOCI: Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest.
- Fair Value through Profit or Loss ("FVTPL"): Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss. This includes all derivative financial assets.

On initial recognition, the Company may irrevocably designate a financial asset that meets the amortized cost or FVOCI criteria as measured at FVTPL if doing so eliminates or significantly reduces an accounting mismatch. On initial recognition of an equity investment that is not held-for-trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in OCI. There is no subsequent reclassification of fair value changes to earnings following the derecognition of the investment. However, dividends that reflect a return on investment continue to be recognized in net earnings. This election is made on an investment-by-investment basis.

At initial recognition, the Company measures a financial asset at its fair value and, in the case of a financial asset not at FVTPL, including transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are recorded as an expense in net earnings.

Financial assets are reclassified subsequent to their initial recognition only if the business model for managing those financial assets changes. The affected financial assets will be reclassified on the first day of the first reporting period following the change in the business model.

A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Impairment of Financial Assets

The Company recognizes loss allowances for expected credit losses ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, Cenovus measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the related financial asset. The Company does not have any financial assets that contain a financing component.

Classification and Measurement of Financial Liabilities

A financial liability is initially classified as measured at amortized cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable.

Financial liabilities at FVTPL (other than financial liabilities designated at FVTPL) are measured at fair value with changes in fair value, along with any interest expense, recognized in net earnings. Other financial liabilities are initially measured at fair value less directly attributable transaction costs and are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in net earnings. Any gain or loss on derecognition is also recognized in net earnings.

A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, it is treated as a derecognition of the original liability and the recognition of a new liability. When the terms of an existing financial liability are altered, but the changes are considered non-substantial, it is accounted for as a modification to the existing financial liability. Where a liability is substantially modified it is considered to be extinguished and a gain or loss is recognized in net earnings based on the difference between the carrying amount of the liability derecognized and the fair value of the revised liability. Where a liability is modified in a non-substantial way, the amortized cost of the liability is remeasured based on the new cash flows and a gain or loss is recorded in net earnings.

Derivatives

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Derivative financial instruments are measured at FVTPL unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings as a gain or loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

V) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2020.

W) Recent Accounting Pronouncements

New Accounting Standards and Interpretations not yet Adopted

There are new accounting standards, amendments to accounting standards and interpretations that are effective for annual periods beginning on or after January 1, 2021 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2020. These standards and interpretations are not expected to have a material impact on the Company's Consolidated Financial Statements. The standard applicable to Cenovus is as follows and will be adopted on its effective date:

Interest Rate Benchmark Reform

On August 27, 2020, the IASB published Interest Rate Benchmark Reform – Phase 2 (Amendments to IFRS 9, *"Financial Instruments*", IAS 39, "*Financial Instruments: Recognition and Measurement*", IFRS 7, "*Financial Instruments: Disclosures*", IFRS 4, "*Insurance Contracts*" and IFRS 16) ("IBOR Phase 2 Amendments"), which provides clarity on the changes after the reform of an interest rate benchmark. The amendments are effective for annual periods beginning on or after January 1, 2021, with early application permitted. The IBOR Phase 2 Amendments primarily relate to the modification of financial instruments, allowing for a practical expedient for modifications required by the reform. The practical expedient for modifications is accounted for by updating the effective interest rate without modification of the financial instrument and is subject to satisfying all qualifying criteria. The Company expects the IBOR Phase 2 Amendments will not have a significant impact on the Consolidated Financial Statements.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in accordance with IFRS requires that Management make estimates and assumptions, and use judgment regarding the reported amounts of assets and liabilities, and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

A) Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in the Company's Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement as either a joint operation or a joint venture requires judgment. Cenovus holds a 50 percent interest in WRB, a jointly controlled entity. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB. As a result, the joint arrangement is classified as a joint operation and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, "*Joint Arrangements*", the Company considered the following:

- The intention of the joint arrangement was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnerships. The past and future development of WRB is dependent on funding from the partners by way of partnership notes payable and loans.
- The WRB working interest relationship is operated whereby the operating partner takes product on behalf of the participants and is modified to account for the operating environment of the refining business.
- Phillips 66, as the operator, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnership from undertaking these roles themselves. In addition, the partnership does not have employees and, as such, are not capable of performing these roles.
- In the arrangement, output is taken by the partners, indicating that the partners have the rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangement.

Exploration and Evaluation Assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Identification of Cash-Generating Units

CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretation. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining, crude-by-rail, railcars, storage tanks and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and reversals.

Determining the Lease Term

In determining the lease term, Management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. The assessment is reviewed if a significant event or a significant change in circumstances occurs which affects this assessment.

B) Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that, if changed, could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of the coronavirus ("COVID-19"). The outbreak and subsequent measures intended to limit the pandemic contributed to significant declines and volatility in financial markets. The pandemic has adversely impacted global commercial activity, including significantly reducing worldwide demand for crude oil.

The full extent of the impact of COVID-19 on the Company's operations and future financial performance is currently unknown. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, its continued impact on capital and financial markets on a macro-scale and any new information that may emerge concerning the severity of the virus. These uncertainties may persist beyond when it is determined how to contain the virus or treat its impact. The outbreak presents uncertainty and risk with respect to the Company, its performance, and estimates and assumptions used by Management in the preparation of its financial results.

The outbreak and current market conditions have increased the complexity of estimates and assumptions used to prepare the annual Consolidated Financial Statements, particularly related to recoverable amounts.

In addition, the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the recoverable amount and could affect the carrying value of the related assets. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

Changes to assumptions could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test recoverable amount and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Conventional segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses. Recoverable amounts for the Company's refining assets, crude-by-rail terminal and related ROU assets use assumptions such as throughput, forward commodity prices, market crack spreads, operating expenses, transportation capacity, future capital expenditures, supply and demand conditions and the terminal values used. Recoverable amounts for the Company's real estate ROU assets use assumptions such as real estate market conditions which includes market vacancy rates and sublease market conditions, price per square footage, real estate space availability and borrowing costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit-adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired and liabilities assumed in a business combination, including contingent consideration and goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparables and discounted cash flows which rely on assumptions such as forward commodity prices, quantity of reserves and resources, production costs, Canadian-U.S. foreign exchange rates and discount rates. Changes in these variables could significantly impact the carrying value of the net assets.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

5. GENERAL AND ADMINISTRATIVE

For the years ended December 31,	**2020**	2019	2018
Salaries and Benefits	**145**	143	205
Administrative and Other	**84**	95	177
Onerous Contract Provisions (Recovery)	**18**	(5)	629
Stock-Based Compensation Expense (Note 32)	**49**	67	9
Other Long-Term Incentive Expense (Recovery)	**(4)**	31	-
	292	331	1,020

6. FINANCE COSTS

For the years ended December 31,	**2020**	2019	2018
Interest Expense – Short-Term Borrowings and Long-Term Debt	**392**	407	516
Net (Discount) Premium on Redemption of Long-Term Debt (Note 24)	**(25)**	(63)	17
Interest Expense – Lease Liabilities (Note 25)	**87**	82	-
Unwinding of Discount on Decommissioning Liabilities (Note 27)	**57**	58	62
Other	**25**	27	32
	536	511	627

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2020**	2019	2018
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued From Canada	**(194)**	(800)	602
Other	**63**	(27)	47
Unrealized Foreign Exchange (Gain) Loss	**(131)**	(827)	649
Realized Foreign Exchange (Gain) Loss	**(50)**	423	205
	(181)	(404)	854

8. DIVESTITURES

On December 2, 2020, the Company sold its Marten Hills assets in northern Alberta to Headwater Exploration Inc. (“Headwater”) for total consideration of $138 million, excluding the retained GORR. A before-tax gain of $79 million was recorded on the sale (after-tax gain – $65 million). Total consideration received consists of $33 million in cash, 50 million common shares valued at $97 million and 15 million share purchase warrants valuedat $8 million at the

date of close. The share purchase warrants have a three-year term and an exercise price of $2.00 per share. The Company retained a GORR in the Marten Hills assets which was reclassified from E&E to PP&E for $41 million on the date of close. The investment in Headwater is held in other assets (see Note 20).

On September 6, 2018, the Company completed the sale of Cenovus Pipestone Partnership ("CPP"), a wholly-owned subsidiary, for cash proceeds of $625 million, before closing adjustments. CPP held the Company's Pipestone and Wembley natural gas and liquids business in northwestern Alberta and included the Company's 39 percent operated working interest in the Wembley gas plant. A before-tax loss of $797 million was recorded on the sale (after-tax – $557 million).

9. OTHER (INCOME) LOSS, NET

For the year ended December 31, 2020, the Company recorded a $100 million loss related to the Keystone XL pipeline project.

The Government of Canada passed the Canada Emergency Wage Subsidy ("CEWS") as part of its COVID-19 Economic Response Plan. The program is effective from March 15, 2020 to June 2021. For the year ended December 31, 2020, the Company recorded $40 million in other income from the CEWS program.

For the year ended December 31, 2020, the Company recognized $24 million of lease income (2019 – $17 million). Lease income is earned on tank subleases, operating leases related to the Company's real estate ROU assets in which Cenovus is the lessor, and from the recovery of non-lease components for operating costs and unreserved parking related to the Company's net investment in finance leases. Finance leases are included in other assets as net investment in finance leases. The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach; therefore, comparative periods were not restated.

10. IMPAIRMENT CHARGES AND REVERSALS

A) Cash-Generating Unit Net Impairments

On a quarterly basis, the Company assesses its CGUs for indicators of impairment or when facts and circumstances suggest the carrying amount may exceed its recoverable amount. Goodwill is tested for impairment at least annually.

2020 Upstream Impairments

During the three months ended March 31, 2020, the Company tested its upstream CGUs and CGUs with associated goodwill for impairment. As a result, the Company recorded an impairment loss of $315 million as additional DD&A in the Conventional segment due to the decline in forward crude oil and natural gas prices. As at March 31, 2020, there was no impairment of goodwill or Oil Sands CGUs.

As at December 31, 2020, indicators of impairment were noted for the Company's Conventional assets due to a change in future development plans since the Company last tested for impairment as at March 31, 2020. Therefore, the Company tested its Conventional CGUs for impairment and determined that the carrying amount was greater than the recoverable amount for certain CGUs and recorded an additional impairment loss of $240 million as DD&A.

For the purpose of impairment testing, goodwill is allocated to the CGU of which it relates.There was no impairment of goodwill as at December 31, 2020.

The following table summarizes the year ended December 31, 2020 impairment losses and estimated recoverable amounts as at December 31, 2020 by CGU:

CGU	Impairment Amount	Recoverable Amount
Clearwater	**260**	**160**
Elmworth-Wapiti	**120**	**259**
Kaybob-Edson	**175**	**384**

Key Assumptions

The recoverable amounts (Level 3) of Cenovus's upstream CGUs were determined based on FVLCOD. Key assumptions in the determination of future cash flows from reserves include crude oil, NGLs and natural gas prices, costs to develop and the discount rate. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates at December 31, 2020. All reserves have been evaluated as at December 31, 2020 by the Company's IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2020, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2021	2022	2023	2024	2025	Average Annual Increase Thereafter
WTI (US$/barrel) (1)	47.17	50.17	53.17	54.97	56.07	2.0%
WCS (C$/barrel) (2)	44.63	48.18	52.10	54.10	55.19	2.0%
Edmonton C5+ (C$/barrel)	59.24	63.19	67.34	69.77	71.18	2.0%
AECO (C$/Mcf) (3)	2.88	2.80	2.71	2.75	2.80	2.0%

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Alberta Energy Company ("AECO") natural gas. Assumes gas heating value of one million British thermal units per thousand cubic feet ("Mcf").

Discount and Inflation Rates

Discounted future cash flows are determined by applying a discount rate between 10 percent and 15 percent based on the individual characteristics of the CGU, and other economic and operating factors. Inflation was estimated at approximately two percent.

Sensitivities

The sensitivity analysis below shows the impact that a change in the discount rate or forward commodity prices would have had on the calculated recoverable amount in the impairment testing completed as at December 31, 2020 for the following CGUs:

	Increase (Decrease) to Recoverable Amount			
	One Percent Increase in the Discount Rate	**One Percent Decrease in the Discount Rate**	**Five Percent Increase in the Forward Price Estimates**	**Five Percent Decrease in the Forward Price Estimates**
Clearwater	**(5)**	**6**	**52**	**(97)**
Elmworth-Wapiti	**(7)**	**8**	**54**	**(96)**
Kaybob-Edson	**(13)**	**14**	**54**	**(106)**

2020 Refining Impairments

As at September 30, 2020, the recovery in demand for refined products from the impact of COVID-19 lagged expectations resulting in higher than anticipated inventory levels. These factors, along with low market crack spreads and crude oil processing runs for North American refineries, were identified as potential indicators of impairment for the Wood River and Borger CGUs. As at September 30, 2020, the carrying amount of the Borger CGU was determined to be greater than the recoverable amount and an impairment charge of $450 million was recorded as additional DD&A in the Refining and Marketing segment. The recoverable amount of the Borger CGU was estimated at $692 million, using a discounted cash flow method in accordance with IFRS. As at September 30, 2020, no impairment of the Wood River CGU was identified. As at December 31, 2020, there were no further indicators of impairment noted since the Company last tested as at September 30, 2020.

Key Assumptions

The recoverable amount (Level 3) of the Borger CGU was determined using FVLCOD. The FVLCOD was calculated based on discounted after-tax cash flows using forward prices and cost estimates. Key assumptions in the determination of future cash flows included forward crude oil prices, forward crack spreads, future capital expenditures, operating costs, terminal values and the discount rate. Forward crack spreads were based on quoted near-month contracts for WTI and spot prices for gasoline and diesel.

Crude Oil and Forward Crack Spreads

Forward prices are based on Management's best estimate and corroborated with third-party data. As at September 30, 2020, the forward prices used to determine future cash flows were:

- WTI forward prices used for 2021 to 2022 ranged from US$36.36 per barrel to US$50.84 per barrel and 2023 to 2025 ranged from US$49.66 per barrel to US$58.74 per barrel.
- WTI to West Texas Sour differential used for 2021 to 2022 ranged from US$0.37 per barrel to US$1.73 per barrel and 2023 to 2025 ranged from US$1.21 per barrel to US$1.81 per barrel.
- Group 3 forward market crack spread used for 2021 to 2022 ranged from US$11.56 per barrel to US$13.23 per barrel and 2023 to 2025 ranged from US$11.79 per barrel to US$16.58 per barrel.
- Subsequent prices were extrapolated using a two percent growth rate to determine future cash flows up to year 2035.

Discount Rates

Discounted future cash flows were determined by applying a discount rate of 10 percent based on the individual characteristics of the CGU, and other economic and operating factors.

Sensitivities

The sensitivity analysis below shows the impact that a change in the discount rate or forward commodity prices would have had on the calculated recoverable amount in the impairment testing completed as at September 30, 2020 for the following CGU:

	Increase (Decrease) to Recoverable Amount			
	One Percent Increase in the Discount Rate	One Percent Decrease in the Discount Rate	Five Percent Increase in the Forward Price Estimates	Five Percent Decrease in the Forward Price Estimates
Borger	(71)	81	263	(264)

2020 ROU Asset Impairments

As at March 31, 2020, the temporary suspension of the Company's crude-by-rail program was considered to be an indicator of impairment for the railcar CGU. As a result, the CGU was tested for impairment and an impairment expense of $3 million was recorded as additional DD&A in the Refining and Marketing segment.

2019 Upstream Impairments

As at December 31, 2019, the Company tested its Conventional CGUs for impairment as there were indicators of impairment due to a decline in forward natural gas prices. As at December 31, 2019, there were no impairments of goodwill or the Company's CGUs.

2018 Net Upstream Impairments

As at December 31, 2018, the Company tested its upstream CGUs for impairment. As at December 31, 2018, there was no impairment of goodwill or the Company's CGUs. However, the impairment test provided evidence that previously recognized impairment losses should be reversed.

As at December 31, 2018, the recoverable amount of the Clearwater CGU was estimated to be $761 million. Earlier in 2018 and 2017, impairment losses of $100 million and $56 million, respectively, were recorded due to a decline in forward prices. The impairment was recorded as additional DD&A in the Conventional segment (formerly Deep Basin). In the fourth quarter of 2018, the Company reversed $132 million of impairment losses, net of the DD&A that would have been recorded had no impairments been recorded. The reversal was due to improved recovery, extensions and well performance and changes to the development plan.

B) Asset Impairments and Write-downs

Exploration and Evaluation Assets

For the year ended December 31, 2020, $9 million and $82 million of previously capitalized E&E costs were written off in the Oil Sands segment and Conventional segment, respectively, as the carrying value was not considered to be recoverable and recorded as exploration expense.

In 2019, $18 million and $64 million of previously capitalized E&E costs were written off in the Oil Sands segment and Conventional segment, respectively, as thecarrying value was not considered to be recoverable and recorded as exploration expense.

In 2018, Management completed a comprehensive review of the Conventional development plan, formerly known as Deep Basin, considering factors such as well inventory, pace of development, infrastructure constraints, economic thresholds and limited capital spending on the assets going forward. As such, previously capitalized E&E costs of $2.1 billion were written off as exploration expense in the Elmworth, Wapiti, Kaybob, Edson and Clearwater areas within the Conventional segment.

Property, Plant and Equipment, Net

For the year ended December 31, 2020, $48 million and $4 million of previously capitalized PP&E costs were written off in the Oil Sands segment and Conventional segment, respectively, as the carrying value was not considered to be recoverable. In addition, $52 million of previously capitalized PP&E costs relating to information technology assets were written off due to synergies identified as a result of the Arrangement. The impairment was recorded as additional DD&A in the Corporate and Eliminations segment.

11. DISCONTINUED OPERATIONS

The results of operations from the former Conventional segment was reported as a discontinued operation.

For the year ended December 31, 2018, the Company recorded net earnings from discontinued operations of $247 million. The cash flows from discontinued operations reported in the Consolidated Statement of Cash Flows were $36 million related to cash from operating activities and $404 million related to cash from investing activities.

On January 5, 2018, the Company completed the sale of its Suffield crude oil and natural gas operations in southern Alberta for cash proceeds of $512 million, before closing adjustments. A before-tax gain on discontinuance of $343 million was recorded on the sale.

12. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	**2020**	2019	2018
Current Tax			
Canada	**(14)**	14	(128)
United States	**1**	3	2
Total Current Tax Expense (Recovery)	**(13)**	17	(126)
Deferred Tax Expense (Recovery)	**(838)**	(814)	(884)
Tax Expense (Recovery) From Continuing Operations	**(851)**	(797)	(1,010)

For the year ended December 31, 2020, a deferred tax recovery was recorded due to an impairment of the Borger CGU, impairment in the Conventional segment and current period operating losses that will be carried forward, excluding unrealized foreign exchange gains and losses on long-term debt. In 2020, the Government of Alberta accelerated the reduction in the provincial corporate tax rate from 12 percent to eight percent.

In 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from 12 percent to eight percent over four years. As a result, the Company recorded a deferred income tax recovery of $671 million for the year ended December 31, 2019. In addition, the Company recorded a deferred income tax recovery of $387 million due to an internal restructuring of the Company's U.S. operations resulting in a step-up in the tax basis of the Company's refining assets.

In 2018, the Company recorded a deferred tax recovery related to current period losses, including the write-down of the Conventional E&E assets and a $78 million recovery arising from an adjustment to the tax basis of the Company's refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in WRB, which due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. The maximum recovery related to the carry back of losses to recover tax paid was reached in 2018.

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

For the years ended December 31,	**2020**	2019	2018
Earnings (Loss) From Continuing Operations Before Income Tax	**(3,230)**	1,397	(3,926)
Canadian Statutory Rate	**24.0%**	26.5%	27.0%
Expected Income Tax Expense (Recovery) From Continuing Operations	**(775)**	370	(1,060)
Effect on Taxes Resulting From:			
Statutory and Other Rate Differences	**19**	(52)	(57)
Non-Taxable Capital (Gains) Losses	**(42)**	(38)	89
Non-Recognition of Capital (Gains) Losses	**(42)**	(39)	87
Adjustments Arising From Prior Year Tax Filings	**(8)**	4	3
Recognition of U.S. Tax Basis	**-**	(387)	(78)
Alberta Corporate Rate Reduction	**(7)**	(671)	-
Other	**4**	16	6
Total Tax Expense (Recovery) From Continuing Operations	**(851)**	(797)	(1,010)
Effective Tax Rate	**26.3%**	(57.1)%	25.7%

The analysis of deferred income tax liabilities and deferred income tax assets is as follows:

For the years ended December 31,	2020	2019
Deferred Income Tax Liabilities		
Deferred Income Tax Liabilities to be Settled Within Twelve Months	**-**	3
Deferred Income Tax Liabilities to be Settled After More Than Twelve Months	**4,146**	4,540
	4,146	4,543
Deferred Income Tax Assets		
Deferred Income Tax Assets to be Recovered Within Twelve Months	**(88)**	(113)
Deferred Income Tax Assets to be Recovered After More Than Twelve Months	**(860)**	(398)
	(948)	(511)
Net Deferred Income Tax Liability	**3,198**	4,032

The deferred income tax assets and liabilities to be settled within twelve months represents Management's estimate of the timing of the reversal of temporary differences and may not correlate to the current income tax expense of the subsequent year.

The movement in deferred income tax liabilities and assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is:

Deferred Income Tax Liabilities	PP&E	Risk Management	Other	Total
As at December 31, 2018	5,450	44	51	5,545
Charged (Credited) to Earnings	(927)	(43)	(7)	(977)
Charged (Credited) to OCI	(25)	-	-	(25)
As at December 31, 2019	4,498	1	44	4,543
Charged (Credited) to Earnings	(367)	(1)	(22)	(390)
Charged (Credited) to OCI	(7)	-	-	(7)
As at December 31, 2020	**4,124**	**-**	**22**	**4,146**

Deferred Income Tax Assets	Unused Tax Losses	Risk Management	Other	Total
As at December 31, 2018	(357)	(1)	(326)	(684)
Charged (Credited) to Earnings	129	-	34	163
Charged (Credited) to OCI	3	-	7	10
As at December 31, 2019	(225)	(1)	(285)	(511)
Charged (Credited) to Earnings	(448)	(12)	12	(448)
Charged (Credited) to OCI	14	-	(3)	11
As at December 31, 2020	**(659)**	**(13)**	**(276)**	**(948)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities as at December 31, 2018	4,861
Charged (Credited) to Earnings	(814)
Charged (Credited) to OCI	(15)
Net Deferred Income Tax Liabilities as at December 31, 2019	4,032
Charged (Credited) to Earnings	(838)
Charged (Credited) to OCI	4
Net Deferred Income Tax Liabilities as at December 31, 2020	**3,198**

The deferred income tax asset of $36 million (2019 – $nil) represents net deductible temporary differences in the U.S. jurisdiction which has been fully recognized, as the probability of realization is expected due to a forecasted taxable income. No deferred tax liability has been recognized as at December 31, 2020 and 2019 on temporary differences associated with investments in subsidiaries and joint arrangements where the Company can control the timing of the reversal of the temporary difference and the reversal is not probable in the foreseeable future.

The approximate amounts of tax pools available, including tax losses, are:

As at December 31,	**2020**	2019
Canada	**6,540**	6,113
United States	**3,117**	2,648
	9,657	8,761

As at December 31, 2020, the above tax pools included $1,682 million (2019 – $696 million) of Canadian federal non-capital losses and $1,084 million (2019 – $188 million) of U.S. federal net operating losses. These losses expire no earlier than 2037.

Also included in the December 31, 2020 tax pools are Canadian net capital losses totaling $85 million (2019 –$188 million), which are available for carry forward to reduce future capital gains. As at December 31, 2020, net capital gains totaling $22 million (2019 – $100 million net capital losses) have been realized, decreasing the net capital loss balance from prior year. The Company has not recognized $254 million (2019 – $262 million) of net capital losses associated with unrealized foreign exchange losses on its U.S. denominated debt.

13. PER SHARE AMOUNTS

A) Net Earnings (Loss) Per Share – Basic and Diluted

For the years ended December 31,	**2020**	2019	2018
Earnings (Loss) From:			
Continuing Operations	**(2,379)**	2,194	(2,916)
Discontinued Operations	**-**	-	247
Net Earnings (Loss)	**(2,379)**	2,194	(2,669)
Basic – Weighted Average Number of Shares	**1,228.9**	1,228.8	1,228.8
Dilutive Effect of Cenovus Net Settlement Rights	**-**	0.6	0.4
Diluted – Weighted Average Number of Shares	**1,228.9**	1,229.4	1,229.2
Basic and Diluted Earnings (Loss) Per Share From: ($)			
Continuing Operations	**(1.94)**	1.78	(2.37)
Discontinued Operations	**-**	-	0.20
	(1.94)	1.78	(2.17)

As at December 31, 2020, 31 million NSRs (2019 – 32 million; 2018 – 34 million) were excluded from the diluted weighted average number of shares as their effect would have been anti-dilutive or their exercise prices exceeded the market price of Cenovus's common shares. These instruments could potentially dilute earnings per share in the future. For further information on the Company's stock-based compensation plans (see Note 32).

B) Common Share Dividend

The Company temporarily suspended its common share dividend in response to the low global oil price environment. Prior to the suspension, the Company paid common share dividends of $77 million or $0.0625 per common share in the first quarter of 2020, all of which were paid in cash (2019 – $260 million or $0.2125 per common share; 2018 – $245 million or $0.20 per common share). The declaration of dividends is at the sole discretion of the Company's Board of Directors and is considered quarterly. The Company's Board of Directors declared a first quarter dividend of $0.0175 per common share, payable on March 31, 2021, to common shareholders of record as of March 15, 2021.

C) Preferred Share Dividend

Subsequent to the closing of the Arrangement on January 1, 2021, the outstanding Husky preferred shares were exchanged for Cenovus preferred shares (see Note 39). The Company's Board of Directors declared first quarter dividends for its Cenovus series 1, 2, 3, 5, and 7 first preferred shares, payable on March 31, 2021, in the amount of $8 million.

14. CASH AND CASH EQUIVALENTS

As at December 31,	**2020**	2019
Cash	**368**	108
Short-Term Investments	**10**	78
	378	186

15. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	**2020**	2019
Accruals	**1,053**	1,221
Prepaids and Deposits	**121**	54
Partner Advances	**175**	16
Trade	**96**	212
Joint Operations Receivables	**35**	36
Other	**8**	17
	1,488	1,556

16. INVENTORIES

As at December 31,	**2020**	2019
Product		
Refining and Marketing	**613**	874
Oil Sands	**382**	570
Conventional	**1**	1
Parts and Supplies	**93**	87
	1,089	1,532

During the year ended December 31, 2020, approximately $9,996 million of produced and purchased inventory was recorded as an expense (2019 – $14,285 million; 2018 – $15,664 million).

As at March 31, 2020, the Company recorded $588 million in non-cash inventory write-downs of its crude oil blend, condensate and refined product inventory. Subsequently, $547 million of inventory that was written down at the end of March was sold and the loss was realized. For the year ended December 31, 2020, the Company reversed $39 million of the inventory write-downs related to March product inventory that was still on hand due to improved refined product and crude oil prices. As at December 31, 2020, the Company recorded a $6 million write-down in refined product inventory.

As at December 31, 2019, the Company recorded a $25 million write-down in refined product inventory. The inventory write-down was realized in 2020.

17. EXPLORATION AND EVALUATION ASSETS

	Total
As at December 31, 2018	785
Additions	73
Exploration Expense (Note 10)	(82)
Change in Decommissioning Liabilities	9
Exchange Rate Movements and Other	2
As at December 31, 2019	787
Additions	48
Transfers to PP&E (Note 18) (1)	(47)
Exploration Expense (Note 10)	(91)
Depletion	(18)
Change in Decommissioning Liabilities	5
Divestitures (Note 8)	(61)
As at December 31, 2020	**623**

(1) Includes the $41 million reclassification of the GORR retained in the sale of the Marten Hills assets (see Note 8).

18. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other (1)	Total
COST					
As at December 31, 2018	28,046	333	5,632	1,213	35,224
Adjustment for Change in Accounting Policy (2)	-	-	(4)	-	(4)
Additions	695	-	228	193	1,116
Change in Decommissioning Liabilities	340	-	9	5	354
Exchange Rate Movements and Other	(9)	-	(288)	3	(294)
Divestitures (Note 8)	(40)	-	-	-	(40)
As at December 31, 2019	29,032	333	5,577	1,414	36,356
Additions	475	-	243	93	811
Transfers From E&E Assets (Note 17)	6	41	-	-	47
Change in Decommissioning Liabilities	(11)	-	3	2	(6)
Exchange Rate Movements and Other	(6)	-	(152)	(1)	(159)
Divestitures	(3)	-	-	-	(3)
As at December 31, 2020	**29,493**	**374**	**5,671**	**1,508**	**37,046**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2018	3,918	333	1,442	833	6,526
Adjustment for Change in Accounting Policy (2)	-	-	(1)	-	(1)
Depreciation, Depletion and Amortization	1,735	-	241	75	2,051
Impairment Charges (Note 10)	20	-	-	10	30
Exchange Rate Movements and Other	31	-	(86)	-	(55)
Divestitures (Note 8)	(29)	-	-	-	(29)
As at December 31, 2019	5,675	333	1,596	918	8,522
Depreciation, Depletion and Amortization	1,768	-	242	109	2,119
Impairment Charges (Note 10)	607	-	450	52	1,109
Exchange Rate Movements and Other	(22)	-	(93)	-	(115)
As at December 31, 2020	**8,028**	**333**	**2,195**	**1,079**	**11,635**
CARRYING VALUE					
As at December 31, 2018	24,128	-	4,190	380	28,698
As at December 31, 2019	23,357	-	3,981	496	27,834
As at December 31, 2020	**21,465**	**41**	**3,476**	**429**	**25,411**

(1) Primarily consists of crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft.
(2) Effective January 1, 2019, the Company adopted IFRS 16.

PP&E includes the following amounts in respect of assets under construction and not subject to DD&A:

As at December 31,	2020	2019
Development and Production	**1,807**	1,836
Refining Equipment	**226**	172
	2,033	2,008

19. RIGHT-OF-USE ASSETS, NET

	Real Estate	Railcars & Barges	Storage Assets (1)	Refining Equipment	Other	Total
COST						
As at January 1, 2019 (2)	517	63	292	13	9	894
Additions	10	436	172	-	6	624
Terminations	-	-	(11)	-	-	(11)
Reclassifications	(8)	-	-	-	-	(8)
Re-measurement	-	(2)	18	(2)	-	14
Exchange Rate Movements and Other	(10)	(2)	(7)	(1)	(1)	(21)
As at December 31, 2019	509	495	464	10	14	1,492
Additions	1	18	22	5	7	53
Terminations	-	-	(1)	-	-	(1)
Modifications	-	-	1	-	(3)	(2)
Reclassifications	(14)	-	-	-	-	(14)
Re-measurement	-	(20)	19	-	(1)	(2)
Exchange Rate Movements and Other	(1)	(13)	(8)	-	(2)	(24)
As at December 31, 2020	**495**	**480**	**497**	**15**	**15**	**1,502**
ACCUMULATED DEPRECIATION						
As at January 1, 2019 (2)	-	-	-	1	-	1
Depreciation	29	55	75	2	4	165
Impairment Charges (Note 10)	3	-	-	-	-	3
Terminations	-	-	(1)	-	-	(1)
Exchange Rate Movements and Other	-	-	(1)	-	-	(1)
As at December 31, 2019	32	55	73	3	4	167
Depreciation	27	86	95	2	5	215
Impairment Charges (Note 10)	-	3	-	-	-	3
Terminations	-	-	(1)	-	-	(1)
Exchange Rate Movements and Other	(1)	(13)	(5)	-	(2)	(21)
As at December 31, 2020	**58**	**131**	**162**	**5**	**7**	**363**
CARRYING VALUE						
As at January 1, 2019 (2)	517	63	292	12	9	893
As at December 31, 2019	477	440	391	7	10	1,325
As at December 31, 2020	**437**	**349**	**335**	**10**	**8**	**1,139**

(1) Includes caverns and tanks.
(2) Effective January 1, 2019, the Company adopted IFRS 16.

20. OTHER ASSETS

As at December 31,	2020	2019
Intangible Assets	**89**	101
Equity Investments (Note 35A)	**52**	52
Investment in Associate (Note 8)	**97**	-
Net Investment in Finance Leases	**52**	30
Long-Term Receivables and Prepaids	**11**	28
Other	**12**	-
	313	211

In 2019, Cenovus entered into an agreement to assume a firm capacity shipper position in a pipeline transportation services agreement from a third party. The fee was recorded as an intangible asset at cost and will be amortized over the life of the contract of approximately 10 years.

21. GOODWILL

As at December 31, 2020 and 2019, the carrying amount of goodwill associated with the Company's Primrose (Foster Creek) CGU and Christina Lake CGUwas $1,171 million and $1,101 million, respectively.

For the purposes of impairment testing, goodwill is allocated to the CGU to which it relates. The assumptions used to test Cenovus's goodwill for impairment as at December 31, 2020 are consistent to those disclosed in Note 10. There was no impairment of goodwill as at December 31, 2020.

22. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	2020	2019
Accruals	**912**	1,085
Trade	**608**	954
Interest	**77**	49
Partner Advances	**175**	16
Employee Long-Term Incentives	**130**	60
Joint Operations Payable	**6**	2
Risk Management	**58**	2
Onerous Contract Provisions	**26**	17
Other	**26**	44
	2,018	2,229

23. SHORT-TERM BORROWINGS

The Company has uncommitted demand facilities of $1.6 billion in place, of which $600 million may be drawn for general purposes, or the full amount can be available to issue letters of credit. As at December 31, 2020, no amount was drawn on these facilities (December 31, 2019 – $nil) and there were outstanding letters of credit aggregating to $441 million (December 31, 2019 – $364 million).

WRB has uncommitted demand facilities of US$300 million (the Company's proportionate share – US$150 million) available to cover short-term working capital requirements. As at December 31, 2020, US$190 million was drawn on these facilities, of which the Company's proportionate share was US$95 million (C$121 million) (December 31, 2019 – $nil).

24. LONG-TERM DEBT AND CAPITAL STRUCTURE

As at December 31,	Notes	2020	2019
Revolving Term Debt (1)	A	-	265
U.S. Dollar Denominated Unsecured Notes	B	7,510	6,492
Total Debt Principal		7,510	6,757
Debt Discounts and Transaction Costs		(69)	(58)
Long-Term Debt		7,441	6,699

(1) Revolving term debt may include Bankers' Acceptances, London Interbank Offered Rate based loans, prime rate loans and U.S. base rate loans.

The weighted average interest rate on outstanding debt, including the Company's proportionate share of the WRB uncommitted demand facilities, for the year ended December 31, 2020 was 4.9 percent (2019 – 5.1 percent).

As at December 31, 2020, the Company is in compliance with all of the terms of its debt agreements.

A) Committed Credit Facilities

Cenovus has in place a committed revolving credit facility that consists of a $1.2 billion tranche and a $3.3 billion tranche with maturity dates of November 30, 2022 and November 30, 2023, respectively. In April 2020, the Company added a committed credit facility with capacity of $1.1 billion to further support the Company's financial resilience in the current market environment. On December 31, 2020, the Company cancelled the $1.1 billion credit facility.

B) U.S. Dollar Denominated Unsecured Notes

The remaining principal amounts of the Company's U.S. dollar denominated unsecured notes are:

	2020		2019	
As at December 31,	US$ Principal Amount	Total C$ Equivalent	US$ Principal Amount	Total C$ Equivalent
3.00% due August 15, 2022	500	637	500	650
3.80% due September 15, 2023	450	573	450	585
5.38% due July 15, 2025	1,000	1,273	-	-
4.25% due April 15, 2027	962	1,225	962	1,249
5.25% due June 15, 2037	583	742	641	833
6.75% due November 15, 2039	1,390	1,770	1,400	1,818
4.45% due September 15, 2042	155	198	155	202
5.20% due September 15, 2043	58	74	58	75
5.40% due June 15, 2047	800	1,018	832	1,080
	5,898	7,510	4,998	6,492

The Company has in place a base shelf prospectus that allows the Company to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in October 2021. Offerings under the base shelf prospectus are subject to market conditions.

On July 30, 2020, Cenovus completed a public offering in the U.S., under the Company's U.S. base shelf prospectus, of senior unsecured notes in the aggregate principal of US$1.0 billion due in 2025. As at December 31, 2020, US$3.7 billion is available under the base shelf prospectus for permitted offerings.

In addition, during the year ended December 31, 2020, the Company paid US$81 million to repurchase a portion of its unsecured notes with a principal amount of US$100 million. A gain on the repurchase of $25 million was recorded in finance costs (see Note 6).

C) Mandatory Debt Payments

As at December 31, 2020	US$ Principal Amount	Total C$ Equivalent
2022	500	637
2023	450	573
2025	1,000	1,273
Thereafter	3,948	5,027
	5,898	7,510

D) Capital Structure

Cenovus's capital structure objectives remain unchanged from previous periods. Cenovus's capital structure consists of shareholders' equity plus Net Debt. Net Debt includes the Company's short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. Cenovus conducts its business and makes decisions consistent with that of an investment grade company. The Company's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, draw down on its credit facilities or repay existing debt, adjust dividends paid to shareholders, repurchase the Company's common shares for cancellation, issue new debt, or issue new shares.

Cenovus monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted Earnings Before Interest, Taxes and DD&A ("Adjusted EBITDA") and Net Debt to Capitalization. These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times over the long-term. This ratio may periodically be above the target due to factors such as persistently low commodity prices.

Net Debt to Adjusted EBITDA *(1)*

As at December 31,	**2020**	2019	2018
Short-Term Borrowings	**121**	-	-
Current Portion of Long-Term Debt	**-**	-	682
Long-Term Debt	**7,441**	6,699	8,482
Less: Cash and Cash Equivalents	**(378)**	(186)	(781)
Net Debt	**7,184**	6,513	8,383
Net Earnings (Loss)	**(2,379)**	2,194	(2,669)
Add (Deduct):			
Finance Costs	**536**	511	628
Interest Income	**(9)**	(12)	(19)
Income Tax Expense (Recovery)	**(851)**	(797)	(920)
Depreciation, Depletion and Amortization	**3,464**	2,249	2,131
Exploration Expense	**91**	82	2,123
Unrealized (Gain) Loss on Risk Management	**56**	149	(1,249)
Foreign Exchange (Gain) Loss, Net	**(181)**	(404)	854
Re-measurement of Contingent Payment	**(80)**	164	50
(Gain) Loss on Discontinuance	**-**	-	(301)
(Gain) Loss on Divestitures of Assets	**(81)**	(2)	795
Other (Income) Loss, Net	**40**	9	13
Adjusted EBITDA	**606**	4,143	1,436
Net Debt to Adjusted EBITDA	**11.9x**	1.6x	5.8x

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated.

Net Debt to Capitalization

As at December 31,	**2020**	2019	2018
Net Debt	**7,184**	6,513	8,383
Shareholders' Equity	**16,707**	19,201	17,468
	23,891	25,714	25,851
Net Debt to Capitalization	**30%**	25%	32%

Cenovus also manages its Net Debt to Capitalization ratio to ensure compliance with the associated covenant as defined in its committed credit facility agreements. Under the terms of Cenovus's committed credit facility, the Company is required to maintain a debt to capitalization ratio, as defined in the agreements, not to exceed 65 percent. The Company is well below this limit.

25. LEASE LIABILITIES

	2020	2019
Lease Liabilities, Beginning of Year	1,916	1,494
Additions	49	590
Interest Expense (Note 6)	87	82
Lease Payments	(284)	(232)
Terminations	(1)	(11)
Modifications	(2)	-
Re-measurement	(2)	15
Exchange Rate Movements and Other	(6)	(22)
Lease Liabilities, End of Year	**1,757**	**1,916**
Less: Current Portion	**184**	**196**
Long-Term Portion	**1,573**	**1,720**

The Company has lease liabilities for contracts related to office space, railcars, barges, storage assets, drilling and service rigs, and other refining and field equipment. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions.

For the years ended December 31,	2020	2019
Variable Lease Payments	**16**	19
Short-Term Lease Payments	**6**	13

The Company has variable lease payments related to property taxes for real estate contracts. Short-term leases are leases with terms of twelve months or less.

The Company has included extension options in the calculation of lease liabilities where the Company has the right to extend a lease term at its discretion and is reasonably certain to exercise the extension option. The Company does not have any significant termination options and the residual amounts are not material.

26. CONTINGENT PAYMENT

	2020	2019
Contingent Payment, Beginning of Year	**143**	132
Re-measurement (1)	**(80)**	164
Liabilities Settled or Payable	**-**	(153)
Contingent Payment, End of Year	**63**	143
Less: Current Portion	**36**	79
Long-Term Portion	**27**	64

(1) Contingent payment is carried at fair value. Changes in fair value are recorded in net earnings.

In connection with the acquisition (the "Acquisition in 2017") from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips"), Cenovus agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52.00 per barrel during the quarter. The quarterly payment will be $6 million for each dollar that the WCS price exceeds $52.00 per barrel. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment. There are no maximum payment terms.

The contingent payment is accounted for as a financial option. The fair value is estimated by calculating the present value of the future expected cash flows using an option pricing model, which assumes the probability distribution for WCS is based on the volatility of WTI options, volatility of Canadian-U.S. foreign exchange rate options and both WTI and WCS futures pricing, and discounted at a credit-adjusted risk-free rate. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. As at December 31, 2020, no amount was payable under this agreement (2019 – $14 million).

27. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the expected future costs associated with the retirement of upstream crude oil and natural gas assets, refining facilities and the crude-by-rail terminal.

The aggregate carrying amount of the obligation is:

	2020	2019
Decommissioning Liabilities, Beginning of Year	**1,235**	875
Liabilities Incurred	**14**	3
Liabilities Settled	**(42)**	(52)
Liabilities Disposed	**(2)**	(8)
Change in Estimated Future Cash Flows	**13**	21
Change in Discount Rate	**(28)**	339
Unwinding of Discount on Decommissioning Liabilities (Note 6)	**57**	58
Foreign Currency Translation	**1**	(1)
Decommissioning Liabilities, End of Year	**1,248**	1,235

As at December 31, 2020, the undiscounted amount of estimated future cash flows required to settle the obligation is $4,953 million (2019 – $5,173 million), which has been discounted using a credit-adjusted risk-free rate of 5.0 percent (2019 – 4.9 percent) and an inflation rate of two percent (2019 – two percent). Most of these obligations are not expected to be paid for several years, or decades, and are expected to be funded from general resources at that time. The Company expects to settle approximately $40 million to $45 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from a change in the timing of decommissioning liabilities over the estimated life of the reserves and an increase in cost estimates.

Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

		2020		2019	
As at December 31,	**Sensitivity Range**	**Increase**	**Decrease**	Increase	Decrease
Credit-Adjusted Risk-Free Rate	± one percent	**(228)**	**313**	(236)	332
Inflation Rate	± one percent	**321**	**(235)**	340	(243)

28. OTHER LIABILITIES

As at December 31,	2020	2019
Employee Long-Term Incentives	**33**	103
Pension and Other Post-Employment Benefit Plan (Note 29)	**91**	73
Onerous Contract Provisions	**39**	46
Other	**18**	19
	181	241

29. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension that includes either a defined contribution or defined benefit component and other post-employment benefit plan. Most of the employees participate in the defined contribution pension. Employees who meet certain criteria may elect to move from the current defined contribution component to a defined benefit component for their future service.

The defined benefit pension provides pension benefits at retirement based on years of service and final average earnings. Future enrollment is limited to eligible employees who meet certain criteria. The Company's OPEB provides certain retired employees with health care and dental benefits until age 65 and life insurance benefits.

The Company is required to file an actuarial valuation of its registered defined benefit pension with the provincial regulator at least every three years. The most recently filed valuation was dated December 31, 2019 and the next required actuarial valuation will be as at December 31, 2022.

A) Defined Benefit and OPEB Plan Obligation and Funded Status

Information related to defined benefit pension and OPEB plans, based on actuarial estimations, is:

	Pension Benefits		OPEB	
As at December 31,	**2020**	2019	**2020**	2019
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**158**	167	**22**	21
Current Service Costs	**13**	11	**1**	1
Interest Costs (1)	**5**	6	**-**	1
Benefits Paid	**(6)**	(36)	**(2)**	(2)
Plan Participant Contributions	**2**	2	**-**	-
Re-measurements:				
(Gains) Losses From Experience Adjustments	**1**	(4)	**(2)**	-
(Gains) Losses From Changes in Financial Assumptions	**15**	12	**1**	1
Defined Benefit Obligation, End of Year	**188**	158	**20**	22
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**107**	113	**-**	-
Employer Contributions	**6**	9	**-**	-
Plan Participant Contributions	**2**	2	**-**	-
Benefits Paid	**(5)**	(35)	**-**	-
Interest Income (1)	**2**	3	**-**	-
Re-measurements:				
Return on Plan Assets (Excluding Interest Income)	**5**	15	**-**	-
Fair Value of Plan Assets, End of Year	**117**	107	**-**	-
Pension and OPEB (Liability) (2)	**(71)**	(51)	**(20)**	(22)

(1) Based on the discount rate of the defined benefit obligation at the beginning of the year.
(2) Pension and OPEB liabilities are included in other liabilities on the Consolidated Balance Sheets.

The weighted average duration of the defined benefit pension and OPEB obligations are 17.4 years and 13.3 years, respectively.

B) Pension and OPEB Costs

	Pension Benefits			OPEB		
For the years ended December 31,	**2020**	2019	2018	**2020**	2019	2018
Defined Benefit Plan Cost						
Current Service Costs	**13**	11	13	**1**	1	1
Past Service Costs – Curtailments	**-**	-	(2)	**-**	-	-
Net Interest Costs	**3**	3	3	**-**	1	1
Re-measurements:						
Return on Plan Assets (Excluding Interest Income)	**(5)**	(15)	7	**-**	-	-
(Gains) Losses From Experience Adjustments	**1**	(4)	-	**(2)**	-	-
(Gains) Losses From Changes in Financial Assumptions	**15**	12	-	**1**	1	(1)
Defined Benefit Plan Cost (Recovery)	**27**	7	21	**-**	3	1
Defined Contribution Plan Cost	**22**	21	22	**-**	-	-
Total Plan Cost	**49**	28	43	**-**	3	1

C) Investment Objectives and Fair Value of Plan Assets

The objective of the asset allocation is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment and credit rating categories.

The allocation of assets between the various types of investment funds is monitored regularly and is re-balanced monthly, if necessary. The asset allocation structure targets an investment of 25 percent to 70 percent in equity securities, 25 percent to 35 percent in fixed income assets, zero percent to 15 percent in real estate assets, zero percent to 10 percent in listed infrastructure assets, zero percent to 10 percent in emerging market debts and zero percent to 10 percent in cash and cash equivalents.

The Company does not use derivative instruments to manage the risks of its plan assets. There has been no change in the process used by the Company to manage these risks from prior periods.

The fair value of the plan assets is:

As at December 31,	**2020**	2019
Equity Funds	**58**	59
Fixed Income Funds	**35**	35
Real Estate Funds	**6**	-
Listed Infrastructure Funds	**8**	9
Emerging Market Debt Funds	**7**	-
Non-Invested Assets	**1**	2
Cash and Cash Equivalents	**2**	2
	117	107

Fair value of the equity, fixed income and listed infrastructure assets are based on the trading price of the underlying funds (Level 1). The fair value of the real estate fund reflects the appraisal valuation for each property investment (Level 2). The fair value of the non-invested assets is the discounted value of the expected future payments (Level 3).

The defined benefit plan does not hold any direct investment in Cenovus shares.

D) Funding

The defined benefit pension is funded in accordance with federal and provincial government pension legislation, where applicable. Contributions are made to trust funds administered by an independent trustee. The Company's contributions to the defined benefit pension plan are based on the most recent actuarial valuation as at December 31, 2019, and direction of the Management Pension Committee and Human Resources and Compensation Committee of the Board of Directors.

Employees participating in the defined benefit pension are required to contribute four percent of their pensionable earnings, up to an annual maximum, and the Company provides the balance of the funding necessary to ensure benefits will be fully provided for at retirement. The expected employer contributions for the year ended December 31, 2021 are $10 million for the defined benefit pension plan. The OPEB is funded on an as required basis.

E) Actuarial Assumptions and Sensitivities

Actuarial Assumptions

The principal weighted average actuarial assumptions used to determine benefit obligations and expenses are as follows:

	Pension Benefits			**OPEB**		
For the years ended December 31,	**2020**	2019	2018	**2020**	2019	2018
Discount Rate	**2.50%**	3.00%	3.50%	**2.50%**	3.00%	3.50%
Future Salary Growth Rate	**3.97%**	3.94%	3.88%	**4.94%**	5.08%	5.08%
Average Longevity (years)	**88.3**	88.2	88.2	**88.2**	88.2	88.1
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**6.00%**	6.00%	6.00%

The discount rates are determined with reference to market yields on high quality corporate debt instruments of similar duration to the benefit obligations at the end of the reporting period.

Sensitivities

The sensitivity of the defined benefit and OPEB obligation to changes in relevant actuarial assumptions is:

	2020		2019	
As at December 31,	**Increase**	**Decrease**	Increase	Decrease
One Percent Change:				
Discount Rate	**(31)**	**40**	(25)	32
Future Salary Growth Rate	**4**	**(4)**	3	(3)
Health Care Cost Trend Rate	**1**	**(1)**	1	(1)
One Year Change in Assumed Life Expectancy	**4**	**(4)**	3	(3)

The sensitivity analysis is based on a change in an assumption while holding all other assumptions constant; however, the changes in some assumptions may be correlated. The same methodologies have been used to calculate the sensitivity of the defined benefit obligation to significant actuarial assumptions as have been applied when calculating the defined benefit pension liability recorded on the Consolidated Balance Sheets.

F) Risks

Through its defined benefit pension and OPEB plans, the Company is exposed to actuarial risks, such as longevity risk, interest rate risk, investment risk and salary risk.

Longevity Risk

The present value of the defined benefit plan obligation is calculated by reference to the best estimate of the mortality of plan participants both during and after their employment. An increase in the life expectancy of participants will increase the defined benefit plan obligation.

Interest Rate Risk

A decrease in corporate bond yields will increase the defined benefit plan obligation, although this will be partially offset by an increase in the return on debt holdings.

Investment Risk

The present value of the defined benefit plan obligation is calculated using a discount rate determined by reference to high quality corporate bond yields. If the return on plan assets is below this rate, a plan deficit will result. Due to the long-term nature of the plan liabilities, a higher portion of the plan assets are invested in equity securities than in debt instruments and real estate.

Salary Risk

The present value of the defined benefit plan obligation is calculated by reference to the future salaries of plan participants. As such, an increase in the salary of the plan participants will increase the defined benefit obligation.

30. SHARE CAPITAL

A) Authorized

Cenovus is authorized to issue an unlimited number of common shares and first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles. Prior to the close of the Arrangement, Cenovus's articles were amended effective December 30, 2020 to create the Cenovus series 1, 2, 3, 4, 5, 6, 7 and 8 first preferred shares.

B) Issued and Outstanding

	2020		2019	
As at December 31,	**Number of Common Shares** (thousands)	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**1,228,828**	**11,040**	1,228,790	11,040
Common Shares Issued Under Stock Option Plan (Note 32)	**42**	**-**	38	-
Outstanding, End of Year	**1,228,870**	**11,040**	1,228,828	11,040

There were no preferred shares outstanding as at December 31, 2020 (2019 – nil).

As at December 31, 2020, there were 27 million (2019 – 26 million) common shares available for future issuance under the stock option plan.

Subsequent to December 31, 2020, the Company issued common shares and first preferred shares in connection to the Arrangement that closed on January 1, 2021 (see Note 39).

C) Paid in Surplus

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana Corporation ("Encana") under the plan of arrangement into two independent energy companies, Encana (now known as Ovintiv Inc.) and Cenovus (pre-arrangement earnings). In addition, paid in surplus includes stock-based compensation expense related to the Company's NSRs discussed in Note 32A.

	Pre-Arrangement Earnings	Stock-Based Compensation	Total
As at December 31, 2018	4,086	281	4,367
Stock-Based Compensation Expense	-	10	10
As at December 31, 2019	4,086	291	4,377
Stock-Based Compensation Expense	-	14	14
As at December 31, 2020	**4,086**	**305**	**4,391**

31. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Pension Plan	Private Equity Instruments	Foreign Currency Translation Adjustment	Total
As at December 31, 2018	(7)	15	1,030	1,038
Other Comprehensive Income (Loss), Before Tax	6	14	(228)	(208)
Income Tax	(1)	(2)	-	(3)
As at December 31, 2019	(2)	27	802	827
Other Comprehensive Income (Loss), Before Tax	(10)	-	(44)	(54)
Income Tax	2	-	-	2
As at December 31, 2020	**(10)**	**27**	**758**	**775**

32. STOCK-BASED COMPENSATION PLANS

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of the Company. Option exercise prices approximate the market value for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options expire after seven years.

Options issued by the Company on or after February 24, 2011 have associated NSRs. The NSRs, in lieu of exercising the option, gives the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option. Alternatively, the holder may elect to exercise the option and receive a net cash payment equal to the excess of the market price received from the sale of the common shares over the exercise price of the option.

The NSRs vest and expire under the same terms and conditions as the underlying options.

Net Settlement Rights

The weighted average unit fair value of NSRs granted during the year ended December 31, 2020 was $2.27 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.19%**
Expected Dividend Yield	**1.77%**
Expected Volatility (1)	**29.74%**
Expected Life (years)	**5.00**

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The following tables summarize information related to the NSRs:

For the year ended December 31, 2020	Number of NSRs (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	31,528	22.61
Granted	5,783	11.73
Exercised	(42)	9.48
Forfeited	(416)	23.52
Expired	(6,256)	32.60
Outstanding, End of Year	**30,597**	**18.52**

	Outstanding NSRs			Exercisable NSRs	
As at December 31, 2020 **Range of Exercise Price** ($)	**Number of NSRs** (thousands)	**Weighted Average Remaining Contractual Life** (years)	**Weighted Average Exercise Price** ($)	**Number of NSRs** (thousands)	**Weighted Average Exercise Price** ($)
5.00 to 9.99	**2,796**	**4.2**	**9.48**	**1,596**	**9.48**
10.00 to 14.99	**12,921**	**5.2**	**12.27**	**4,189**	**13.53**
15.00 to 19.99	**2,691**	**2.3**	**19.47**	**2,691**	**19.47**
20.00 to 24.99	**3,078**	**1.1**	**22.26**	**3,078**	**22.26**
25.00 to 29.99	**8,540**	**0.1**	**28.37**	**8,540**	**28.37**
30.00 to 34.99	**571**	**0.5**	**32.27**	**571**	**32.27**
	30,597	**2.9**	**18.52**	**20,665**	**21.94**

The Arrangement on January 1, 2021 resulted in the accelerated vesting of outstanding NSRs held by non-executive employees and certain non-executive officers of the Company. In accordance with their terms, 2,738 thousand additional NSRs vested and were exercisable as a result of the accelerated vesting on January 1, 2021.

B) Performance Share Units

Cenovus has granted PSUs to certain employees under its Performance Share Unit Plan for Employees. PSUs are time-vested whole-share units that entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. The number of PSUs eligible to vest is determined by a multiplier that ranges from zero percent to 200 percent and is based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $65 million as at December 31, 2020 (2019 – $53 million) in the Consolidated Balance Sheets for PSUs based on the market value of Cenovus's common shares at the end of the year. The Arrangement on January 1, 2021 resulted in the accelerated vesting of outstanding PSUs held by non-executive employees and certain non-executive officers of the Company. As a result, the intrinsic value was $51 million as at December 31, 2020. In accordance with their terms, 7,055 thousand PSUs will be settled, in cash, subsequent to December 31, 2020 based on the 30-day volume weighted average trading price prior to the date of closing. The intrinsic value of vested PSUs was $nil as at December 31, 2019.

The following table summarizes the information related to the PSUs held by Cenovus employees:

For the year ended December 31, 2020	Number of PSUs (thousands)
Outstanding, Beginning of Year	6,912
Granted	3,846
Vested and Paid Out	(1,223)
Cancelled	(449)
Units in Lieu of Dividends	198
Outstanding, End of Year	**9,284**

C) Restricted Share Units

Cenovus has granted RSUs to certain employees under its Restricted Share Unit Plan for Employees. RSUs are whole-share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. RSUs generally vest after three years.

RSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as stock-based compensation costs over the vesting period. Fluctuations in the fair value are recognized as stock-based compensation costs in the period they occur.

The Company has recorded a liability of $61 million as at December 31, 2020 (2019 – $63 million) in the Consolidated Balance Sheets for RSUs based on the market value of Cenovus's common shares at the end of the year. The Arrangement on January 1, 2021 resulted in the accelerated vesting of outstanding RSUs held by employees and certain non-executive officers of the Company. As a result, the intrinsic value was $60 million as at December 31, 2020. In accordance with their terms, 8,237 thousand RSUs will be settled, in cash, subsequent to December 31, 2020 based on the 30-day volume weighted average trading price prior to the date of closing. The intrinsic value of vested RSUs was $nil as at December 31, 2019.

The following table summarizes the information related to the RSUs held by Cenovus employees:

For the year ended December 31, 2020	Number of RSUs (thousands)
Outstanding, Beginning of Year	8,372
Granted	2,686
Vested and Paid Out	(2,606)
Cancelled	(234)
Units in Lieu of Dividends	212
Outstanding, End of Year	**8,430**

D) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and certain employees may receive DSUs, which are equivalent in value to a common share of the Company. Eligible employees have the option to convert either zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $10 million as at December 31, 2020 (2019 – $16 million) in the Consolidated Balance Sheets for DSUs based on the market value of Cenovus's common shares at the end of the year. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant. In connection with the Arrangement, the termination of a DSU holder that is a Cenovus director or employee will result in the settlement and redemption of DSUs, in cash based on the five day volume weighted average trading price prior to the date of redemption, in accordance with the terms of the related DSU Plan.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees:

For the year ended December 31, 2020	Number of DSUs (thousands)
Outstanding, Beginning of Year	1,237
Granted to Directors	288
Granted	30
Units in Lieu of Dividends	33
Redeemed	(255)
Outstanding, End of Year	**1,333**

E) Total Stock-Based Compensation

For the years ended December 31,	2020	2019	2018
Net Settlement Rights	**11**	9	6
Performance Share Units	**19**	15	(6)
Restricted Share Units	**23**	34	9
Deferred Share Units	**(4)**	9	-
Stock-Based Compensation Expense	**49**	67	9
Stock-Based Compensation Costs Capitalized	**16**	20	4
	65	87	13

33. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	2020	2019	2018
Salaries, Bonuses and Other Short-Term Employee Benefits	**605**	567	580
Post-Employment Benefits	**33**	29	30
Stock-Based Compensation Expense (Note 32)	**49**	67	9
Other Long-Term Incentive Benefits	**(4)**	31	-
Termination Benefits	**9**	6	63
	692	700	682

Stock-based compensation includes the costs recorded during the year associated with NSRs, PSUs, RSUs and DSUs.

34. RELATED PARTY TRANSACTIONS

Key Management Compensation

Key management includes Directors (executive and non-executive), Executive Officers, Senior Vice-Presidents and Vice-Presidents. The compensation paid or payable to key management is:

For the years ended December 31,	2020	2019	2018
Salaries, Director Fees and Short-Term Benefits	**21**	24	20
Post-Employment Benefits	**3**	2	3
Stock-Based Compensation	**15**	22	5
Other Long-Term Incentive Benefits	**1**	1	-
Termination Benefits	**6**	-	9
	46	49	37

Post-employment benefits represent the present value of future pension benefits earned during the year.

35. FINANCIAL INSTRUMENTS

Cenovus's financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, net investment in finance leases, accounts payable and accrued liabilities, risk management assets and liabilities, investments in the equity of private companies, long-term receivables, lease liabilities, contingent payment, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

A) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of these instruments.

The fair values of long-term receivables and net investment in finance leases approximate their carrying amounts due to the specific non-tradeable nature of these instruments.

Long-term debt is carried at amortized cost. The estimated fair value of long-term debt has been determined based on the period-end tradingprices on the secondary market (Level 2). As at December 31, 2020, the carrying value of Cenovus's long-term debt was $7,441 million and the fair value was $8,608 million (2019 carrying value – $6,699 million; fair value – $7,610 million).

Equity investments classified at FVOCI comprise equity investments in private companies. The Company classifies certain private equity instruments at FVOCI as they are not held for trading and fair value changes are not reflective of the Company's operations. These assets are carried at fair value on the Consolidated Balance Sheets in other assets. Fair value is determined based on recent private placement transactions (Level 3) when available.

The following table provides a reconciliation of changes in the fair value of private equity investments classified at FVOCI:

	2020	2019
Fair Value, Beginning of Year	**52**	38
Change in Fair Value (1)	**-**	14
Fair Value, End of Year	**52**	52

(1) Changes in fair value are recorded in OCI.

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil swaps, futures, natural gas futures, and if entered into, crude oil options, condensate futures and swaps, foreign exchange swaps, interest rate swaps and cross currency interest rate swaps. Crude oil, condensate and, if entered into, natural gas contracts are recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price for the same commodity, using quoted market prices or the period-end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of foreign exchange swaps are calculated using external valuation models which incorporate observable market data, including foreign exchange forward curves (Level 2) and the fair value of interest rate swaps are calculated using external valuation models which incorporate observable market data, including interest rate yield curves (Level 2). The fair value of cross currency interest rate swaps are calculated using external valuation models which incorporate observable market data, including foreign exchange forward curves (Level 2) and interest rate yield curves (Level 2).

Summary of Unrealized Risk Management Positions

	2020			2019		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Crude Oil, Natural Gas and Condensate	**5**	**58**	**(53)**	5	2	3

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value:

As at December 31,	**2020**	2019
Level 2 – Prices Sourced From Observable Data or Market Corroboration	**(53)**	3

Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

The following table summarizes the changes in the fair value of Cenovus's risk management assets and liabilities:

	2020	2019
Fair Value of Contracts, Beginning of Year	**3**	160
Fair Value of Contracts Realized During the Year	**252**	7
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year	**(308)**	(156)
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**-**	(8)
Fair Value of Contracts, End of Year	**(53)**	3

Financial assets and liabilities are offset only if Cenovus has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. Cenovus offsets risk management assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. No additional unrealized risk management positions are subject to an enforceable master netting arrangement or similar agreement that are not otherwise offset.

The following table provides a summary of the Company's offsetting risk management positions:

	2020			2019		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	**70**	**123**	**(53)**	13	10	3
Amount Offset	**(65)**	**(65)**	**-**	(8)	(8)	-
Net Amount per Consolidated Financial Statements	**5**	**58**	**(53)**	5	2	3

The derivative liabilities do not have credit risk-related contingent features. Due to credit practices that limit transactions according to counterparties' credit quality, the change in fair value through profit or loss attributable to changes in the credit risk of financial liabilities is immaterial.

Cenovus pledges cash collateral with respect to certain of these risk management contracts, which is not offset against the related financial liability. The amount of cash collateral required will vary daily over the life of these risk management contracts as commodity prices change. Additional cash collateral is required if, on a net basis, risk management payables exceed risk management receivables on a particular day. As at December 31, 2020, $59 million was pledged as cash collateral (2019 – $nil).

C) Fair Value of Contingent Payment

The contingent payment is carried at fair value on the Consolidated Balance Sheets. Fair value is estimated by calculating the present value of the expected future cash flows using an option pricing model (Level 3), which assumes the probability distribution for WCS is based on the volatility of WTI options, volatility of Canadian to U.S. foreign exchange rate options and both WTI and WCS futures pricing, and discounted at a credit-adjusted risk-free rate of 2.0 percent. Fair value of the contingent payment has been calculated by Cenovus's internal valuation team which consists of individuals who are knowledgeable and have experience in fair value techniques. As at December 31, 2020, the fair value of the contingent payment was estimated to be $63 million (2019 – $143 million).

As at December 31, 2020, average WCS forward pricing for the remaining term of the contingent payment is $42.93 per barrel. The average implied volatility of WTI options and the Canadian to U.S. foreign exchange rate options used to value the contingent payment were 35.6 percent and 6.8 percent, respectively. Changes in the following inputs to the option pricing model, with fluctuations in all other variables held constant, could have resulted in an unrealized gain (loss) impacting earnings before income tax as follows:

As at December 31, 2020	**Sensitivity Range**	**Increase**	**Decrease**
WCS Forward Prices	± $5.00 per barrel	**(41)**	**32**
WTI Option Volatility	± five percent	**(18)**	**17**
Canadian to U.S. Dollar Foreign Exchange Rate Option Volatility	± five percent	**7**	**(10)**

As at December 31, 2019	**Sensitivity Range**	**Increase**	**Decrease**
WCS Forward Prices	± $5.00 per barrel	(129)	80
WTI Option Volatility	± five percent	(45)	42
Canadian to U.S. Dollar Foreign Exchange Rate Option Volatility	± five percent	10	(19)

D) Earnings Impact of (Gains) Losses From Risk Management Positions

For the years ended December 31,	**2020**	2019	2018
Realized (Gain) Loss (1)	**252**	7	1,554
Unrealized (Gain) Loss (2)	**56**	149	(1,249)
(Gain) Loss on Risk Management From Continuing Operations	**308**	156	305

(1) Realized gains and losses on risk management are recorded in the reportable segment to which the derivative instrument relates.
(2) Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

36. RISK MANAGEMENT

Cenovus is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates as well as credit risk and liquidity risk.

To manage exposure to interest rate volatility, the Company may periodically enter into interest rate swap contracts. To mitigate the Company's exposure to foreign exchange rate fluctuations, the Company periodically enters into foreign exchange contracts. To manage interest costs on short-term borrowings, the Company periodically enters into cross currency interest rate swaps. As at December 31, 2020, there were no interest rate, foreign exchange or cross currency interest rate swap contracts outstanding.

To manage exposure to commodity price movements between when products are produced or purchased and when sold to the customer or used by Cenovus, the Company may periodically enter into financial positions as a part of ongoing operations to market the Company's production and physical inventory positions of crude oil and condensate volumes. The Company has entered into risk management positions to help capture the incremental margin expected to be received in future periods at the time products will be sold. To mitigate overall exposure to the fluctuations in commodity prices, the Company may also enter into financial positions to protect the near-term and future cash flows. As at December 31, 2020, the fair value of financial positions was a net liability of $53 million and primarily consisted of crude oil and condensate instruments.

Net Fair Value of Risk Management Positions

As at December 31, 2020	Notional Volumes (1) (2)	Terms (3)	Weighted Average Price (1) (2)	Fair Value Asset (Liability)
Crude Oil and Condensate Contracts				
WTI Fixed - Sell	19.6 MMbbls	January 2021 - June 2022	US$43.99/bbl	**(113)**
WTI Fixed - Buy	11.7 MMbbls	February 2021 - June 2022	US$44.55/bbl	**59**
Other Financial Positions (4)				**1**
Total Fair Value				**(53)**

(1) Million barrels ("MMbbls"). Barrel ("bbl").
(2) Notional volumes and weighted average price represent various contracts over the respective terms. The notional volumes and weighted average price may fluctuate from month to month as it represents the averages for various individual contracts with different terms.
(3) Contract terms represents averages for various individual contracts with different terms and range from one to twenty-three months.
(4) Other financial positions consist of risk management positions related to WCS and condensate differential contracts, Belvieu and natural gas fixed contracts and the Company's Refining and Marketing segment.

A) Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of forward commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments.

The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy does not allow the use of derivative instruments for speculative purposes.

Crude Oil – The Company has used commodity futures and swaps, basis price risk management contracts, and costless collars to partially mitigate its exposure to the commodity price risk on its crude oil sales and to protect both near-term and future cash flows. Cenovus has entered into a number of transactions to help protect against widening light/heavy crude oil price differentials and to manage exposure to commodity price movements between when products are produced or purchased and when sold to the customer or used by Cenovus. In addition, the Company has entered into risk management positions to help mitigate the risk to incremental margin expected to be received in future periods at the time products will be sold.

Condensate – The Company has used commodity futures and swaps, as well as basis price risk management contracts to partially mitigate its exposure to the commodity price risk on its condensate purchases.

Natural Gas – The Company has used fixed price and basis instruments to partially mitigate its natural gas commodity price risk.

Sensitivities

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to independent fluctuations in commodity prices, with all other variables held constant. Management believes the fluctuations identified in the table below are a reasonable measure of volatility.

The impact of fluctuating commodity prices on the Company's open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

As at December 31, 2020	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to WTI and Condensate Hedges	**(44)**	**44**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**(2)**	**2**

As at December 31, 2019	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to WTI and Condensate Hedges	3	(3)
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	5	(5)

B) Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on reported results.

As disclosed in Note 7, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada. As at December 31, 2020, Cenovus had US$5,898 million in U.S. dollar debt issued from Canada (2019 – US$4,998 million). In respect of these financial instruments, the impact of changes in the Canadian per U.S. dollar exchange rate would have resulted in a change to the foreign exchange (gain) loss as follows:

For the years ended December 31,	2020	2019
$0.05 Increase in the Canadian per U.S. Dollar Foreign Exchange Rate	**300**	250
$0.05 Decrease in the Canadian per U.S. Dollar Foreign Exchange Rate	**(300)**	(250)

C) Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. To manage exposure to interest rate volatility, the Company periodically enters into interest rate swap contracts. As at December 31, 2020, Cenovus had no interest rate swap contracts outstanding (2019 – $nil). To manage interest costs on short-term borrowings, the Company periodically enters into cross currency interest rate swaps. As at December 31, 2020, Cenovus had no cross currency interest rate swap contracts outstanding (2019 – $nil).

As at December 31, 2020, the increase or decrease in net earnings for a one percent change in interest rates on floating rate debt amounts to $1 million (2019 – $3 million; 2018 – $nil). This assumes the amount of fixed and floating debt remains unchanged from respective balance sheet dates.

D) Credit Risk

Credit risk arises from the potential that the Company may incur a financial loss if a counterparty to a financial instrument fails to meet its financial or performance obligations in accordance with agreed terms. Cenovus has in place a Credit Policy approved by the Audit Committee and the Board of Directors designed to ensure that its credit exposures are within an acceptable risk level as determined by the Company's Enterprise Risk Management Policy. The Credit Policy outlines the roles and responsibilities related to credit risk, sets a framework for how credit exposures will be measured, monitored and mitigated, and sets parameters around credit concentration limits.

Cenovus assesses the credit risk of new counterparties and continues risk-based monitoring of all counterparties on an ongoing basis. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. Cenovus's exposure to its counterparties is within credit policy tolerances. The maximum credit risk exposure associated with accounts receivable and accrued revenues, net investment in finance leases, risk management assets, and long-term receivables is the total carrying value.

As at December 31, 2020, approximately 98 percent of the Company's accruals, joint operations, trade receivables and net investment in finance leases were with investment grade counterparties (2019 – 97 percent), and as at December 31, 2020 and 2019, substantially all of the Company's accounts receivable were outstanding less than 60 days. The average expected credit loss on the Company's accruals, joint operations, trade receivables and net investment in finance leases was 0.5 percent as at December 31, 2020 (2019 – 0.3 percent). As at December 31, 2020, Cenovus had one counterparty (2019 – one counterparty) whose net settlement position individually accounted for more than 10 percent of the fair value of the Company's accruals, joint operations, trade receivables and net investment in finance leases.

E) Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit, which may be impacted by the Company's credit ratings. As disclosed in Note 24, over the long term, Cenovus targets a Net Debt to Adjusted EBITDA of less than 2.0 times to manage the Company's overall debt position.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn capacity on its committed credit facility and uncommitted demand facilities as well as availability under its base shelf prospectus. As at December 31, 2020, Cenovus had $378 million in cash and cash equivalents, $4.5 billion available on its committed credit facility, $1.1 billion available on its uncommitted demand facilities, of which $600 million may be drawn for general purposes, or the full amount can be available to issue letters of credit. A further US$55 million representing the Company's available proportionate share of the WRB uncommitted demand facilities is available. In addition, Cenovus has unused capacity of US$3.7 billion under its base shelf prospectus, the availability of which is dependent on market conditions.

On January 1, 2021, with the close of the Arrangement, Cenovus obtained access to additional sources of capital (see Note 39).

Undiscounted cash outflows relating to financial liabilities are:

As at December 31, 2020	Less than 1 Year	Years 2 and 3	Years 4 and 5	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	**2,018**	**-**	**-**	**-**	**2,018**
Short-Term Borrowings (1)	**121**	**-**	**-**	**-**	**121**
Long-Term Debt (1)	**385**	**1,965**	**1,966**	**8,627**	**12,943**
Contingent Payment (2)	**36**	**28**	**-**	**-**	**64**
Lease Liabilities (1)	**254**	**445**	**365**	**1,412**	**2,476**

As at December 31, 2019	Less than 1 Year	Years 2 and 3	Years 4 and 5	Thereafter	Total
Accounts Payable and Accrued Liabilities	2,229	-	-	-	2,229
Long-Term Debt (1)	344	1,338	1,465	9,326	12,473
Contingent Payment (2)	79	69	-	-	148
Lease Liabilities (1)	277	466	410	1,544	2,697

(1) Principal and interest, including current portion.
(2) Refer to Note 35C for fair value assumptions.

37. SUPPLEMENTARY CASH FLOW INFORMATION

The following table provides a reconciliation of liabilities to cash flows arising from financing activities:

For the years ended December 31,	**2020**	2019	2018
Interest Paid	**381**	457	564
Interest Received	**5**	12	19
Income Taxes Paid	**18**	17	116

The following table provides a reconciliation of cash flows arising from financing activities:

	Dividends Payable	**Short-Term Borrowings**	**Long-Term Debt**	**Lease Liabilities**
As at December 31, 2017	-	-	9,513	-
Changes From Financing Cash Flows:				
Repayment of Long-Term Debt	-	-	(1,144)	-
Net Issuance (Repayment) of Revolving Long-Term Debt	-	-	(20)	-
Dividends Paid	(245)	-	-	-
Non-Cash Changes:				
Dividends Declared	245	-	-	-
Foreign Exchange (Gain) Loss	-	-	817	-
Finance Costs	-	-	(2)	-
As at December 31, 2018	-	-	9,164	-
Adjustment for Change in Accounting Policy (1)	-	-	-	1,494
Changes From Financing Cash Flows:				
Dividends Paid	(260)	-	-	-
Repayment of Long-Term Debt	-	-	(2,279)	-
Net Issuance (Repayment) of Revolving Long-Term Debt	-	-	276	-
Principal Repayment of Leases	-	-	-	(150)
Non-Cash Changes:				
Dividends Declared	260	-	-	-
Foreign Exchange (Gain) Loss	-	-	(399)	(23)
Gain on Repurchase of Debt and Amortization of Debt Issuance Costs	-	-	(63)	-
Lease Additions	-	-	-	590
Re-measurement of Lease Liabilities	-	-	-	15
Lease Terminations	-	-	-	(11)
Other	-	-	-	1
As at December 31, 2019	-	-	6,699	1,916
Changes From Financing Cash Flows:				
Dividends Paid	(77)	-	-	-
Issuance (Repayment) of Short-Term Borrowings	-	117	-	-
Issuance of Long-Term Debt	-	-	1,326	-
Repayment of Long-Term Debt	-	-	(112)	-
Net Issuance (Repayment) of Revolving Long-Term Debt	-	-	(220)	-
Principal Repayment of Leases	-	-	-	(197)
Non-Cash Changes:				
Dividends Declared	77	-	-	-
Foreign Exchange (Gain) Loss	-	4	(231)	(6)
Gain on Repurchase of Debt and Amortization of Debt Issuance Costs	-	-	(20)	-
Lease Additions	-	-	-	49
Lease Terminations	-	-	-	(1)
Lease Modifications	-	-	-	(2)
Re-measurement of Lease Liabilities	-	-	-	(2)
Other	-	-	(1)	-
As at December 31, 2020	**-**	**121**	**7,441**	**1,757**

(1) Effective January 1, 2019, the Company adopted IFRS 16.

38. COMMITMENTS AND CONTINGENCIES

A) Commitments

Future payments for the Company's commitments are below. A commitment is an enforceable and legally binding agreement to make a payment in the future for the purchase of goods and services. These items exclude amounts recorded in the Consolidated Balance Sheets.

As at December 31, 2020	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage (1)	**1,014**	**954**	**1,341**	**1,444**	**1,107**	**15,537**	**21,397**
Real Estate (2)	**34**	**36**	**38**	**41**	**44**	**604**	**797**
Capital Commitments	**1**	**2**	**-**	**-**	**-**	**-**	**3**
Other Long-Term Commitments	**104**	**45**	**32**	**32**	**24**	**85**	**322**
Total Payments (3)	**1,153**	**1,037**	**1,411**	**1,517**	**1,175**	**16,226**	**22,519**

As at December 31, 2019	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage (1)	1,005	959	1,026	1,456	1,381	15,672	21,499
Real Estate (2)	35	36	38	39	42	662	852
Other Long-Term Commitments	104	44	36	34	28	108	354
Total Payments (3)	1,144	1,039	1,100	1,529	1,451	16,442	22,705

(1) Includes transportation commitments of $14 billion (2019 – $13 billion) that are subject to regulatory approval or have been approved, but are not yet in service. Terms are up to 20 years subsequent to the date of commencement.

(2) Relates to the non-lease components of lease liabilities consisting of operating costs and unreserved parking for office space. Excludes committed payments for which a provision has been provided.

(3) Contracts undertaken on behalf of WRB are reflected at Cenovus's 50 percent interest.

Transportation and storage commitments include future commitments relating to storage tank leases of $31 million, that have not yet commenced.

As at December 31, 2020, there were outstanding letters of credit aggregating to $441 million issued as security for performance under certain contracts (2019 – $364 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 36 and commitments related to the Arrangement are disclosed in Note 39.

B) Contingencies

Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on its Consolidated Financial Statements.

Decommissioning Liabilities

Cenovus is responsible for the retirement of long-lived assets at the end of their useful lives. Cenovus has recorded a liability of $1,248 million, based on current legislation and estimated costs, related to its upstream properties, refining facilities and the crude-by-rail terminal. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

The tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.

Contingent Payment

In connection with the Acquisition in 2017, Cenovus agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52.00 per barrel during the quarter. As at December 31, 2020, the estimated fair value of the contingent payment was $63 million (2019 – $143 million) (see Note 26).

39. SUBSEQUENT EVENT

Cenovus and Husky Combine to Create a New Integrated Energy Company

A) Summary of the Acquisition

On October 25, 2020, Cenovus announced that it had entered into a definitive agreement to combine with Husky. The transaction was accomplished through a plan of arrangement pursuant to which Cenovus acquired all the issued and outstanding common shares of Husky in exchange for common shares and common share purchase warrants of Cenovus. In addition, all of the issued and outstanding Husky preferred shares were exchanged for Cenovus preferred shares with substantially identical terms. The Arrangement closed on January 1, 2021.

The Arrangement will combine oil sands and heavy oil assets with extensive transportation, storage and logistics and downstream infrastructure, creating opportunities to optimize the margin captured across the heavy oil value chain. The combined company will be largely integrated, reducing exposure to Alberta heavy oil price differentials while maintaining exposure to global commodity prices.

The Arrangement was accounted for using the acquisition method pursuant to IFRS 3, "*Business Combinations*". Under the acquisition method, assets and liabilities are measured at their estimated fair value on the date of acquisition with the exception of income tax, stock-based compensation, lease liabilities and ROU assets. The total consideration was allocated to the tangible and intangible assets acquired and liabilities assumed.

B) Purchase Price Allocation

Cenovus acquired all the issued and outstanding Husky common shares in consideration for the issuance of 0.7845 Cenovus common shares plus 0.0651 Cenovus warrants for each Husky common share. Cenovus issued 788.5 million Cenovus common shares with a fair value of $6.1 billion, based on the December 31, 2020 closing share price of $7.75, as reported on the TSX. In addition, 65.4 million common share purchase warrants were issued. Each whole warrant entitles the holder to acquire one Cenovus common share for a period of five years at an exercise price of $6.54 per share. The fair value of the warrants was estimated to be $216 million. Cenovus also acquired all the issued and outstanding Husky preferred shares in exchange for 36.0 million Cenovus first preferred shares with substantially identical terms and a fair value of $519 million. The outstanding Husky stock options were also exchanged for Cenovus replacement stock options. Each replacement stock option entitles the holder to acquire 0.7845 of a Cenovus common share at an exercise price per share of a Husky stock option divided by 0.7845. The fair value of the replacement stock options was estimated to be $9 million.

The preliminary purchase price allocation is based on Management's best estimate of the assets acquired and liabilities assumed. Upon finalizing the value of net assets acquired, adjustments may be required.

The following table summarizes the details of the consideration and the recognized amounts of assets acquired and liabilities assumed at the date of the acquisition.

As at	January 1, 2021
Consideration	
Common Shares	**6,111**
Preferred Shares	**519**
Share Purchase Warrants	**216**
Replacement Stock Options	**9**
Non-Controlling Interest	**11**
Total Consideration and Non-Controlling Interest	**6,866**
Identifiable Assets Acquired and Liabilities Assumed	
Cash	**735**
Restricted Cash	**164**
Accounts Receivable and Accrued Revenues	**1,272**
Inventories	**1,118**
Property, Plant and Equipment, Intangible Assets and Deferred Income Tax Assets	**15,227**
Right-of-Use Assets	**1,137**
Long-Term Income Tax Receivable	**202**
Other Assets	**200**
Investments in Joint Ventures	**457**
Accounts Payable and Accrued Liabilities	**(2,224)**
Income Tax Payable	**(59)**
Current Portion of Long-Term Debt	**(40)**
Long-Term Debt	**(6,602)**
Lease Liabilities	**(1,447)**
Decommissioning Liabilities	**(2,835)**
Other Liabilities	**(439)**
Total Identifiable Net Assets	**6,866**

The fair value of trade and other receivables acquired as part of the acquisition is $1.1 billion, with a gross contractual amount of $1.2 billion. As of the acquisition date, the best estimate of the contractual cash flows not expected to be collected is $36 million.

Cenovus incurred $29 million of acquisition related costs, excluding common share, preferred share and warrant issuance costs. These costs have been included in transaction costs in the Consolidated Statements of Earnings (Loss).

C) Liquidity and Commitments

Subsequent to the closing of the Arrangement on January 1, 2021, Cenovus obtained access to additional sources of liquidity including: $735 million in cash, $3.7 billion available on Husky's committed credit facilities and $508 million available on Husky's uncommitted demand facilities. Husky's committed credit facilities have a capacity of $4.0 billion and its uncommitted demand facilities have a capacity of $975 million, of which $850 million may be drawn for general purposes, or the full amount can be available to issue letters of credit.

The Arrangement resulted in the assumption of Husky's non-cancellable contracts and other commercial commitments. As at January 1, 2021, total commitments assumed by Cenovus were $18.7 billion, of which $7.4 billion were for various transportation and storage commitments. Transportation commitments include $1.7 billion that are subject to regulatory approval or have been approved but are not yet in service.

D) Segmented Disclosures

Management is in the process of finalizing the determination of the operating and reporting segments for the Company. It is anticipated that the Company's business will be conducted predominately through an upstream and downstream segment. Management continues to evaluate how the segments may be presented and will make a final determination during the first quarter of 2021.

The upstream business is anticipated to be reported as follows:

- **Oil Sands,** includes the development and production of heavy oil and bitumen in northeast Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Christina Lake, Sunrise and Tucker oil sands projects, as well as Lloydminster Thermal and Cold and Enhanced Oil Recovery assets.
- **Conventional,** includes the operations from conventional oil and natural gas production, including processing operations in the Deep Basin and other parts of Western Canada.
- **Offshore,** includes the offshore operations, exploration and development activities in the Asia Pacific region and Atlantic Canada region.

The downstream business is anticipated to be reported as follows:

- **Canadian Manufacturing,** includes Cenovus's owned and operated upgrader and asphalt refinery in Lloydminster, the owned and operated crude-by-rail terminal and two ethanol plants.
- **Retail,** includes the Canadian retail, commercial and wholesale channels.
- **U.S. Manufacturing,** includes the U.S. operations of wholly owned refineries in Lima and Superior, the jointly owned Wood River and Borger refineries with operator Phillips 66 and the jointly owned Toledo refinery with BP Products North America Inc. as operator.

Exhibit 99.4



Cenovus Energy Inc.

Supplementary Information – Oil and Gas Activities (unaudited)

For the Year Ended December 31, 2020

(Canadian Dollars)

DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES TOPIC 932 "EXTRACTIVE ACTIVITIES – OIL AND GAS" (unaudited)

The following select disclosures of Cenovus Energy Inc.'s ("Cenovus" or the "Company") reserves and other oil and gas information have been prepared in accordance with United States ("U.S.") Financial Accounting Standards Board ("FASB") Topic 932, "*Extractive Activities – Oil and Gas*" and the U.S. disclosure requirements of the Securities and Exchange Commission ("SEC").

All amounts pertaining to Cenovus's audited Consolidated Financial Statements are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). Unless otherwise noted, all dollars are in millions of Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

On October 25, 2020, Cenovus announced that it had agreed to merge with Husky Energy Inc. ("Husky"). The transaction was accomplished through a plan of arrangement (the "Arrangement") pursuant to which Cenovus acquired all the issued and outstanding common shares of Husky in exchange for common shares and common share purchase warrants of Cenovus. The Arrangement closed on January 1, 2021. This document excludes the reserves acquired as the Arrangement closed subsequent to December 31, 2020.

For a discussion of the material impact of the Arrangement on certain of Cenovus's reserves data and certain other oil and gas information included in the Company's 2020 annual information form ("AIF"), refer to the *"Reserves Data and Other Oil and Gas Information"*section of the Company's AIF filed with securities regulatory authorities in Canada (available on SEDAR at sedar.com) and the U.S. (available on EDGAR at sec.gov), and available on the Company's website at cenovus.com."

RESERVES DATA

The SEC Modernization of Oil and Gas Reporting final rules require that proved after royalty reserves be estimated using existing economic conditions (constant pricing). Cenovus's results have been calculated using the average of the first-day-of-the-month prices for the prior twelve-month period. This same twelve-month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves ("SMOG"). Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause Cenovus's share of future production from Canadian reserves to be materially different from that presented.

The reserves disclosed are effective December 31, 2020, and were prepared by the independent, qualified reserves evaluators ("IQREs") McDaniel & Associates Consultants Ltd. and GLJ Ltd. There are significant differences between reserves evaluated under the SEC requirements and those presented in the Company's AIF filed under National Instrument 51-101 "*Standards of Disclosure for Oil and Gas Activities*" ("NI 51-101"). NI 51-101 requires disclosure of before royalties reserves and the associated values using forecasted prices and costs.

The reserves presented in this supplemental information are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond the Company's control. In general, estimates of economically recoverable bitumen, crude oil, natural gas liquids and natural gas reserves and the future net cash flows derived therefrom are based upon a number of variable factors and assumptions, including but not limited to: product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including with respect to environmental regulations, royalty payments and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities, all of which may vary considerably from actual results.

All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable bitumen, crude oil, natural gas liquids and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Cenovus's actual production, sales, royalty payments, taxes and development and operating expenditures with respect to its reserves may vary from current estimates and such variances may be material. Actual reserves may be greater than or less than the estimates disclosed. For a full discussion of Cenovus's material risk factors refer to "Risk Management and Risk Factors" in the Company's annual 2020 Management's Discussion and Analysis included in the annual report on Form 40-F of which this document forms a part.

Estimates with respect to reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production rates. Canadian reserves, as presented on a net basis, assume royalty rates in existence at the time the estimates were made.

The reserves data contained herein is dated February 8, 2021 with an effective date of December 31, 2020.

OIL AND GAS RESERVES INFORMATION

All of Cenovus's reserves are located in Alberta and British Columbia, Canada.

Net Proved Reserves (Cenovus Share After Royalties) [1][2]
Average Fiscal-Year Prices

	Bitumen	Crude Oil	Natural Gas Liquids	Natural Gas	Total
	(MMbbls) [3]	(MMbbls) [3]	(MMbbls) [3]	(Bcf) [3]	(MMBOE) [3]
2019					
Beginning of year	4,115	12	46	1,059	4,350
Revisions and improved recovery	(212)	-	1	3	(211)
Extensions and discoveries	14	2	2	32	22
Purchase of reserves in place	-	-	-	1	-
Sale of reserves in place	-	-	-	(1)	-
Production	(103)	(2)	(8)	(158)	(139)
End of year	3,814	12	41	936	4,022
Developed	764	8	32	761	930
Undeveloped	3,050	4	9	175	3,092
Total	3,814	12	41	936	4,022
2020					
Beginning of year	**3,814**	**12**	**41**	**936**	**4,022**
Revisions and improved recovery	**580**	**(2)**	**(4)**	**(125)**	**553**
Extensions and discoveries	**-**	**3**	**-**	**9**	**5**
Purchase of reserves in place	**-**	**-**	**-**	**9**	**2**
Sale of reserves in place	**-**	**(7)**	**-**	**-**	**(7)**
Production	**(124)**	**(2)**	**(6)**	**(137)**	**(155)**
End of year	**4,270**	**4**	**31**	**692**	**4,420**
Developed	**817**	**3**	**23**	**557**	**936**
Undeveloped	**3,453**	**1**	**8**	**135**	**3,484**
Total	**4,270**	**4**	**31**	**692**	**4,420**

(1) Definitions:
(a) "Net" reserves are the remaining reserves attributable to Cenovus, after deduction of estimated royalties and including royalty interests.
(b) "Proved" oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations, i.e., prices and costs as of the date the estimate is made.
(c) "Developed" oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods in which the cost of the required equipment is relatively minor compared to the cost of a new well.
(d) "Undeveloped" reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.
(2) Estimates of total net proved bitumen, crude oil, natural gas liquids, or natural gas reserves are not filed by Cenovus with any U.S. federal authority or agency other than the SEC.
(3) "Million barrels" is abbreviated as MMbbls, "billion cubic feet" is abbreviated as Bcf, and "million barrels of oil equivalent" is abbreviated as MMBOE.

Changes to Reserves

The explanation of significant year-over-year changes in the Company's net proved reserves for the years ended December 31, 2020 and December 31, 2019 is set forth below.

Year ended December 31, 2020

The changes to the Company's net proved bitumen reserves in 2020 are explained as follows:

- *Revisions and improved recovery:* Decreased bitumen prices resulted in lower royalties payable for the Company's Christina Lake and Foster Creek properties which resulted in an increase in net proved reserves of 454 million barrels. Improved recovery performance at Christina Lake and Foster Creek resulted in an increase in net proved reserves of 126 million barrels.

The changes to the Company's net proved reserves of crude oil, natural gas liquids and natural gas in 2020 are explained as follows:

- *Revisions and improved recovery:* Changes to product pricing resulted in net proved reserves of crude oil decreasing by one million barrels and natural gas increasing by four billion cubic feet, respectively. Updates to the Conventional segment development plan decreased net proved reserves of crude oil, natural gas liquids and natural gas by one million barrels, four million barrels and 129 billion cubic feet, respectively.
- *Extensions and discoveries:* Conventional segment development identified net proved reserves of crude oil and natural gas of three million barrels and nine billion cubic feet, respectively.
- *Purchase of reserves in place:* The Company completed several minor acquisitions in its Conventional segment, increasing its net proved reserves of natural gas by nine billion cubic feet.
- *Sale of reserves in place:* The Company sold its Marten Hills property in December 2020, reducing its net proved reserves of crude oil by seven million barrels.

Year ended December 31, 2019

The changes to the Company's net proved bitumen reserves in 2019 are explained as follows:

- *Revisions and improved recovery:* Increased bitumen prices resulted in higher royalties payable for the Company's Christina Lake and Foster Creek properties which resulted in a decrease in net proved reserves of 212 million barrels.
- *Extensions and discoveries:* Recognition of a phase expansion at Christina Lake increased the Company's net proved reserves by 14 million barrels.

The changes to the Company's net proved reserves of crude oil, natural gas liquids and natural gas in 2019 are explained as follows:

- *Extensions and discoveries:* The Marten Hills development identified two million barrels of net proved crude oil reserves. Conventional segment development identified net proved reserves of natural gas liquids and natural gas of two million barrels and 32 billion cubic feet, respectively.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

In calculating SMOG, the average of the first-day-of-the-month prices for the prior twelve-month period and cost assumptions were applied to Cenovus's annual future production from net proved reserves to determine cash inflows. Future production and development costs do not include any cost inflation and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of SMOG is based upon the discounted future net cash flows prepared by IQREs in relation to the reserves they respectively evaluated, and adjusted to the extent provided by contractual arrangements such as price risk management activities, in existence at year end and to account for asset retirement obligations and future income taxes.

Cenovus cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of Cenovus's oil and gas properties, nor the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil, natural gas liquids and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values contributed by Cenovus's enhancement of the netback price from market optimization activities.

Computation of the SMOG was based on the following average of the first-day-of-the-month benchmark prices for the twelve-month period before the end of the year:

	Crude Oil and Natural Gas Liquids				Natural Gas	
	WTI (1) Cushing Oklahoma	**WCS (2)**	**Edmonton MSW (3)**	**Edmonton C5+**	**Henry Hub Louisiana**	**AECO (4)**
	(US$/bbl)	(C$/bbl)	(C$/bbl)	(C$/bbl)	(US$/MMBtu)	(C$/MMBtu)
2020	**39.57**	**36.37**	**45.76**	**50.07**	**1.98**	**2.13**
2019	55.69	55.65	67.09	69.19	2.58	1.76

(1) WTI is an abbreviation for West Texas Intermediate.
(2) WCS is an abbreviation for Western Canadian Select.
(3) MSW is an abbreviation for Mixed Sweet Blend.
(4) AECO is an abbreviation for Alberta Energy Company.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

($ millions)	2020	2019
Future cash inflows	**101,980**	164,640
Less future:		
Production costs	**41,248**	38,880
Development costs	**22,501**	22,625
Asset retirement obligation payments (1)	**3,384**	3,524
Income taxes	**6,950**	22,031
Future net cash flows	**27,897**	77,580
Less 10 percent annual discount for estimated timing of cash flow	**18,163**	50,370
Discounted future net cash flow	**9,734**	27,210

(1) Includes future abandonment and reclamation costs associated with existing and future wells having attributed reserves, non-reserves wells and gathering systems, batteries, plants and processing facilities.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

($ millions)	2020	2019
Balance, beginning of year	**27,210**	10,783
Changes resulting from:		
Sales of oil and gas produced during the period, net of operating costs (1)	**(1,625)**	(3,723)
Extensions, discoveries and improved recovery, net of related cost	**13**	153
Purchases of proved reserves in place	**5**	1
Sales of proved reserves in place	**(18)**	(1)
Net change in prices and production costs (1)	**(28,210)**	24,360
Revisions to quantity estimates	**1,262**	(454)
Accretion of discount	**3,456**	1,325
Previously estimated development costs incurred, net of change in future development costs	**2,620**	75
Other	**(415)**	(425)
Net change in income taxes	**5,436**	(4,884)
Balance, end of year	**9,734**	27,210

(1) On January 1, 2019, Cenovus adopted IFRS 16,"Leases" ("IFRS 16"), which prescribes a different accounting treatment for operating leases than U.S. Generally Accepted Accounting Principles ("US GAAP"). Under US GAAP, the amortization of a right-of-use asset and interest expense related to an operating lease are recorded by nature of the expense on the income statement (production costs). Under IFRS 16, amortization of a right-of-use asset and interest expense are classified as depreciation expense and finance costs, respectively. As a result, changes in SMOG due to the amortization of right-of-use assets and interest payments have been included by Cenovus in "Net change in prices and production costs".

OTHER FINANCIAL INFORMATION

Results of Operations

($ millions)	2020	2019
Oil and gas sales to external customers, net of royalties, transportation and blending and realized risk management	**2,761**	4,683
Intersegment sales	**276**	417
	3,037	5,100
Less:		
Operating costs and accretion of asset retirement obligations	**1,468**	1,434
Depreciation, depletion and amortization	**2,564**	1,862
Inventory Write-Down (Reversal)	**316**	-
Exploration expense	**91**	82
Operating income	**(1,402)**	1,722
Income taxes	**(336)**	456
Results of operations	**(1,066)**	1,266

Capitalized Costs

($ millions)	2020	2019
Proved oil and gas properties	**29,867**	29,365
Unproved oil and gas properties (1)	**623**	787
Total capital cost	**30,490**	30,152
Accumulated depreciation, depletion and amortization	**8,379**	6,008
Net capitalized costs	**22,111**	24,144

(1) Unproved oil and gas properties include exploration and evaluation assets for which no proved reserves have been recognized.

Costs Incurred

($ millions)	**2020**	2019
Acquisitions		
Unproved (1)	**12**	4
Proved (2) (3)	**6**	5
Total acquisitions	**18**	9
Exploration costs	**46**	73
Development costs	**459**	686
Total costs incurred	**523**	768

(1) An unproved property is a property to which no proved or probable reserves have been specifically attributed.
(2) A proved property is a property to which proved and probable reserves have been specifically attributed.
(3) Asset retirement costs are included in the year of acquisition.

Exhibit 99.5

Certification of Chief Executive Officer
Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934

I, Alex J. Pourbaix, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

DATED: February 9, 2021

/s/ Alex J. Pourbaix
Alex J. Pourbaix
President & Chief Executive Officer
(Principal Executive Officer)

Exhibit 99.6

Certification of Chief Financial Officer
Pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934

I, Jeffrey R. Hart, certify that:

1. I have reviewed this annual report on Form 40-F of Cenovus Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

DATED: February 9, 2021

/s/ Jeffrey R. Hart

Jeffrey R. Hart
Executive Vice-President &
Chief Financial Officer
(Principal Financial Officer)

Exhibit 99.7

Certification Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes Oxley Act of 2002

In connection with the annual report of Cenovus Energy Inc. (the "Company") on Form 40–F for the year ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Alex J. Pourbaix, President & Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED: February 9, 2021

/s/ Alex J. Pourbaix

Alex J. Pourbaix

President & Chief Executive Officer

Exhibit 99.8

Certification Pursuant to 18 U.S.C. Section 1350, As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the annual report of Cenovus Energy Inc. (the "Company") on Form 40–F for the year ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Jeffrey R. Hart, Executive Vice-President & Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

DATED: February 9, 2021

/s/ Jeffrey R. Hart

Jeffrey R. Hart

Executive Vice-President &
Chief Financial Officer

Exhibit 99.9



CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in this Annual Report on Form 40-F for the year ended December 31, 2020 of Cenovus Energy Inc. of our report dated February 8, 2021, relating to the consolidated financial statements, and the effectiveness of internal control over financial reporting, which appears in the Exhibit 99.3 to this Annual Report on Form 40-F.

We also consent to the incorporation by reference in the Registration Statements on Form F-10 (File No. 333-233702), Form S-8 (File Nos. 333-163397 and 333-251886), Form F-3D (File No. 333-202165) of Cenovus Energy Inc. of our report dated February 8, 2021 referred to above. We also consent to the reference to us under the heading “Interests of Experts”, which appears in the Annual Information Form included in Exhibit 99.1 to this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statements.

/s/ PricewaterhouseCoopers LLP

Calgary, Alberta, Canada
February 9, 2021

PricewaterhouseCoopers LLP
111 5th Avenue SW, Suite 3100, East Tower, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825, www.pwc.com/ca

“PwC” refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership.

Exhibit 99.10

CONSENT OF INDEPENDENT PETROLEUM ENGINEER

We hereby consent to the use and reference to our name and report evaluating a portion of Cenovus Energy Inc.'s oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, estimated using forecast prices and costs, and the information derived from our report, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2020 and Cenovus Energy Inc.'s registration statements on Form F-10 (File No. 333-233702), Form S-8 (File Nos. 333-163397 and 333-251886) and Form F-3D (File No. 333-202165), filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

McDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ Michael J. Verney

Michael J. Verney, P. Eng.
Executive Vice President

Calgary, Alberta
February 9, 2021

2200, Bow Valley Square 3, 255 - 5 Avenue SW, Calgary AB T2P 3G6 Tel: (403) 262-5506 Fax: (403) 233-2744 www.mcdan.com

Exhibit 99.11

CONSENT OF INDEPENDENT PETROLEUM ENGINEER

We hereby consent to the use and reference to our name and report evaluating a portion of Cenovus Energy Inc.'s oil and gas reserves data, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, estimated using forecast prices and costs, and the information derived from our report, as described or incorporated by reference in Cenovus Energy Inc.'s annual report on Form 40-F for the year ended December 31, 2020 and Cenovus Energy Inc.'s registration statements on Form F-10 (File No. 333-233702), Form S-8 (File Nos. 333-163397 and 333-251886) and Form F-3D (File No. 333-202165) filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended or the Securities Act of 1933, as amended, as applicable.

Yours truly,

GLJ LTD.

/s/ Jodi L. Anhorn

Jodi L. Anhorn, P. Eng.
President and Chief Executive Officer

Calgary, Alberta
February 9, 2021