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

FORM 40-F

☐ REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934
☒ ANNUAL REPORT PURSUANT TO SECTION 13(A) OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2024 Commission File Number 001-36258

VEREN INC.

(Exact name of Registrant as specified in its charter)

Alberta	**1311**	**Not Applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

Suite 2000, 585-8th Avenue S.W.
Calgary, Alberta
T2P 1G1
(403) 693-0020
(Address and telephone number of registrant's principle executive offices)

CT Corporation System
28 Liberty Street
New York, NY 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 pursuant to Section 12(b) of the Act.

Title of each class	**Trading Symbol(s)**	**Name of each exchange on which registered**
Common Shares	**VRN**	**New York Stock Exchange**

Securities 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 the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

611,816,627 Common Shares (as at December 31, 2024).

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.

☒

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

☐

The annual report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the Registrant's Registration Statement under the Securities Act of 1933, as amended: Form F-10 (File No. 333-275312), Form S-8 (File No. 333-226210) and Form F-3D (File No. 333-205592)

EXPLANATORY NOTE

Veren Inc. (the “Registrant” or “we”) is a Canadian issuer eligible to file its annual report pursuant to Section 13 of Exchange Act, on Form 40-F pursuant to the multi-jurisdictional disclosure system of the Exchange Act. We are a “foreign private issuer” as defined in Rule 3b-4 under the Exchange Act. Accordingly, our equity securities are exempt from Sections 14(a), 14(b), 14(c), 14(f) and 16 of the Exchange Act pursuant to Rule 3a12-3.

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 40-F and the exhibits attached hereto contain or incorporate by reference “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Please see “Special Notes to Reader” in the Annual Information Form of the Registrant for the year ended December 31, 2024, filed as Exhibit 99.1 to this Annual Report on Form 40-F for a discussion of risks, uncertainties, and assumptions that could cause actual results, performance or achievements to differ materially from those expressed in, or implied by, these forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These forward-looking statements are based on the beliefs, expectations and opinions of management on the date the statements are made. We do not assume any obligation to update forward-looking statements, except as required by applicable securities laws, if circumstances or management’s beliefs, expectations or opinions should change.

PRINCIPAL DOCUMENTS

The following documents are filed as part of this Annual Report on Form 40-F:

A. Annual Information Form

For the Registrant’s Annual Information Form for the fiscal year ended December 31, 2024, see Exhibit 99.1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the Registrant’s Audited Consolidated Financial Statements for the fiscal year ended December 31, 2024, including the report of its Independent Auditor (PCAOB ID 271) with respect thereto, see Exhibit 99.2 of this Annual Report on Form 40-F.

C. Management’s Discussion and Analysis

For the Registrant’s Management’s Discussion and Analysis of the operating and financial results for the fiscal year ended December 31, 2024, see Exhibit 99.3 of this Annual Report on Form 40-F.

D. Supplementary Information

For the Registrant’s Supplementary Information about Extractive Activities - Oil and Gas (unaudited) for the fiscal year ended December 31, 2024, see Exhibit 99.10 of this Annual Report on Form 40-F.

DISCLOSURE CONTROLS AND PROCEDURES

A. Certifications

The required disclosure is included in Exhibits 99.4, 99.5, 99.6 and 99.7 of 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, 2024, an internal evaluation was conducted under the supervision of and with the participation of the Registrant's management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Registrant's "disclosure controls and procedures" as defined in Rule 13a-15(e) under Securities and Exchange Act of 1934, as amended (the "Exchange Act"). Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of the Registrant's disclosure controls and procedures were effective in ensuring that the information required to be disclosed in the reports that the Registrant files with or submits to the Securities and Exchange Commission (the "Commission") is recorded, processed, summarized and reported, within the required time periods.

It should be noted that while the President and Chief Executive Officer and the Chief 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 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 "Management's Report" that accompanies the Registrant's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2024, filed as Exhibit 99.2 to this Annual Report on Form 40-F.

D. Attestation of Report of Independent Auditor

The attestation report of PricewaterhouseCoopers LLP is included in the Independent Auditor's Report that accompanies the Registrant's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2024, filed as Exhibit 99.2 of this Annual Report on Form 40-F, and is incorporated herein by reference.

E. Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2024, there were no changes in the Registrant's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant's internal control over financial reporting.

TAX MATTERS

Purchasing, holding or disposing of securities of the Registrant may have tax consequences under the laws of the United States and Canada that are not described in this Annual Report on Form 40-F.

NOTICES PURSUANT TO REGULATION BTR

None.

AUDIT COMMITTEE FINANCIAL EXPERT

The Registrant's Board of Directors has determined that Mr. M. Jackson, Ms. J. Jenson Labrie, and Mr. C. Bieber are "audit committee financial experts" (as that term is defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its audit committee and are "independent" (as defined by the New York Stock Exchange corporate governance rules applicable to foreign private issuers).

The Securities and Exchange Commission has indicated that the designation or identification of a person as an "audit committee financial expert" does not (i) mean that such person is an "expert" for any purpose, including without limitation for purposes of Section 11 of the Securities Act of 1933, (ii) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the audit committee and the board of directors in the absence of such designation or identification, or (iii) affect the duties, obligations or liability of any other member of the audit committee or the board of directors.

CODE OF ETHICS

The Registrant has adopted a "code of ethics" (as that term is defined in paragraph 9(b) of General Instruction B to Form 40-F) ("Code of Ethics"), which is applicable to the directors, officers, employees and consultants of the Registrant and its affiliates (including, its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions). The Code of Ethics is available on the Registrant's website at https://vrn.com/esg/governance.

In the past fiscal year, the Registrant has not granted any waiver, including an implicit waiver, from any provision of its Code of Ethics.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The required disclosure is included under the heading "External Auditor Services Fees" in the Registrant's Annual Information Form for the year ended December 31, 2024, filed as Exhibit 99.1 to this Annual Report on Form 40-F, and is incorporated herein by reference.

PRE-APPROVAL POLICIES AND PROCEDURES

The information required is included under the heading "*Relationship and External Auditors*" in Appendix A - Audit Committee - Terms of Reference of the Registrant's Annual Information Form for the fiscal year ended December 31, 2024, incorporated by reference as Exhibit 99.1 to this Annual Report on Form 40-F.

HOURS EXPENDED ON AUDIT ATTRIBUTED TO PERSONS OTHER THAN THE PRINCIPAL ACCOUNTANT'S EMPLOYEES

Not Applicable.

RECOVERY OF ERRONEOUSLY AWARDED COMPENSATION

The Registrant has adopted a compensation recovery policy (referred to as the "Executive Compensation Clawback Policy") as required by NYSE listing standards and pursuant to Rule 10D-1 of the Exchange Act. The Executive Compensation Clawback Policy is filed as Exhibit 97 to this Form 40-F. At no time during or after the fiscal year ended December 31, 2024 (as of the date of this Annual Report), was the Registrant required to prepare an accounting restatement that required recovery of erroneously awarded compensation pursuant to the Executive Compensation Clawback Policy and, as of December 31, 2024, there was no outstanding balance of erroneously awarded compensation to be recovered from the application of the Executive Compensation Clawback Policy to a prior restatement.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant does not have any commitments or obligations, including contingent obligations, arising from arrangements with unconsolidated entities or persons (which are not otherwise discussed in the Registrant's Management's Discussion and Analysis for the fiscal year ended December 31, 2024, filed as Exhibit 99.3 to this annual report on Form 40-F), that have or are reasonably likely to have a material current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, cash requirements or capital resources.

DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The required disclosure is included under the heading “Contractual Obligations and Commitments” in the Registrant’s Management’s Discussion and Analysis of the operating and financial results for the year ended December 31, 2024, filed as Exhibit 99.3 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 Registrant’s Audit Committee members consist of Mr. M. Jackson, Mr. C. Bieber, Ms. J. Jenson Labrie, Mr. F. Langlois and Mr. M. Stadnyk all of whom, in the opinion of the directors, are independent (as determined under Rule 10A-3 of the Exchange Act.)

Please refer to the Company’s AIF attached as Exhibit 99.1 to this annual report on Form 40-F for details in connection with each of these members and their qualifications.
The members of the Audit Committee do not have fixed terms and are appointed and replaced from time to time by resolution of the directors.
The Audit Committee meets with the CEO, CFO and the Company’s independent auditors to review and inquire into matters affecting financial reporting, the system of internal accounting and financial controls, as well as audit procedures and audit plans. The Audit Committee also recommends to the Board of Directors which independent registered public auditing firm should be appointed by the Company. In addition, the Audit Committee reviews and recommends to the Board of Directors for approval the annual financial statements and the Management’s Discussion and Analysis of Financial Condition and Results of Operations, and undertakes other activities required by exchanges on which the Company’s securities are listed and by regulatory authorities to which the Company is held responsible.
The full text of the Audit Committee Terms of Reference is disclosed in the Company’s AIF, attached hereto as Exhibit 99.1, and is incorporated by reference in this annual report on Form 40-F.

NYSE STATEMENT OF CORPORATE GOVERNANCE DIFFERENCES

As a Canadian corporation listed on the NYSE, we are not required to comply with most of the NYSE’s corporate governance standards, and instead may comply with Canadian corporate governance practices. However, we are required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. These significant differences are disclosed on our website at https://vrn.com/esg/governance. Except as disclosed on our website, we are in compliance with the NYSE corporate governance standards in all significant respects.

MINE SAFETY DISCLOSURE

Pursuant to Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, issuers that are operators, or that have a subsidiary that is an operator, of a coal or other mine in the United States are required to disclose in their periodic reports filed with the SEC information regarding specified health and safety violations, orders and citations, related assessments and legal actions, and mining-related fatalities under the regulation of the Federal Mine Safety and Health Review Administration under the Federal Mine Safety and Health Act of 1977. During the fiscal year ended December 31, 2024, we were not subject to any of the specified violations, orders, citations or other legal actions under the Federal Mine Safety and Health Act of 1977.

DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

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 in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

DISCLOSURE PURSUANT TO SECTION 13(r) OF THE EXCHANGE ACT

In accordance with Section 13(r) of the Exchange Act, the Registrant is required to include certain disclosures in its periodic reports if it or any of its affiliates knowingly engaged in certain specified activities during the period covered by the report. Neither the Registrant nor is affiliates have knowingly engaged in any transaction or dealing reportable under Section 13(r) of the Exchange Act during the year ended December 31, 2024.

CONSENT TO SERVICE OF PROCESS

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.

Any change to the name or address of the Registrant's agent for service shall be communicated promptly to the Commission by amendment to 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 report to be signed on its behalf by the undersigned, thereto duly authorized.

Date: February 27, 2025

Veren Inc.

By: /s/ Ken Lamont

Name: Ken Lamont

Title: Chief Financial Officer

Form 40-F Table of Contents

Exhibit No.	Document
97	Clawback Policy
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2024.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2024 together with the Report of Independent Registered Public Accounting Firm thereon.
99.3	Management's Discussion and Analysis of the operating and financial results of the Registrant for the year ended December 31, 2024.
99.4	Certification of Chief Executive Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.5	Certification of Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.6	Certification of Chief Executive Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.7	Certification of Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.8	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm
99.9	Consent of McDaniel & Associates Consultants Ltd., Independent Engineers
99.10	Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
101	Interactive Data File
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

Exhibit 97

Clawback Policy

INTRODUCTION

POLICY

The purpose of this Veren Inc. (the "Company") Clawback Policy (this "Policy") is to enable the Company to recover Erroneously Awarded Compensation in the event that the Company is required to prepare an Accounting Restatement. This Policy is intended to comply with all laws, government regulations, orders or stock exchange listing requirements applicable to the Company, including, but not limited to, the requirements set forth in Section 303A.14 of the NYSE Listed Company Manual (collectively, "Applicable Law" and shall be construed and interpreted in accordance with such intent. Unless otherwise defined in this Policy, capitalized terms shall have the meaning ascribed to such terms in Section 7.

Administration

This Policy shall be administered by the Human Resource and Compensation Committee (the "Committee") of the Board unless the Board determines to administer this Policy itself. The Committee has full and final authority to make all determinations under this Policy, in each case to the extent permitted under Applicable Law and in compliance with (or pursuant to an exemption from the application of) Applicable Law, including Section 409A of the Code. All determinations and decisions made by the Committee pursuant to the provisions of this Policy shall be final, conclusive and binding on all persons, including the Company, its affiliates, its shareholders and Executive Officers. Any action or inaction by the Committee with respect to an Executive Officer under this Policy in no way limits the Committee's actions or decisions not to act with respect to any other Executive Officer under this Policy or under any similar policy, agreement or arrangement, nor shall any such action or inaction serve as a waiver of any rights the Company may have against any Executive Officer other than as set forth in this Policy.

Application

This Policy applies to all Incentive-Based Compensation received by a person: (a) after beginning service as an Executive Officer; (b) who served as an Executive Officer at any time during the performance period for such Incentive-Based Compensation; (c) while the Company had a class of securities listed on a the Toronto Stock Exchange, the NYSE, or any other national securities exchange or a national securities association; and (d) during the three completed fiscal years immediately preceding the Accounting Restatement Date. This Policy also applies to the compensation, in addition to Incentive-Based Compensation, referred to in Section 11 for the purposes thereof. In addition to such last three completed fiscal years, the preceding clause (d) includes any transition period that results from a change in the Company's fiscal year within or immediately following such three completed fiscal years; provided, however, that a transition period between the last day of the Company's previous fiscal year end and the first day of its new fiscal year that comprises a period of nine to twelve months shall be deemed a completed fiscal year. For purposes of this Section 3, Incentive-Based Compensation is deemed received in the Company's fiscal period during which the Financial Reporting Measure specified in the Incentive-Based Compensation award is attained, even if the payment or grant of the Incentive-Based Compensation occurs after the end of that period. For the avoidance of doubt, Incentive-Based Compensation that is subject to both a Financial Reporting Measure vesting condition and a service-based vesting condition shall be considered received when the relevant Financial Reporting Measure is achieved, even if the Incentive-Based Compensation continues to be subject to the service-based vesting condition.

Recovery Requirement

In the event of an Accounting Restatement, the Company must recover, reasonably promptly, Erroneously Awarded Compensation, in amounts determined pursuant to this Policy. The Company's obligation to recover Erroneously Awarded Compensation is not dependent on if or when the Company files restated financial statements. Recovery under this Policy with respect to an Executive Officer shall not require the finding of any misconduct by such Executive Officer or such Executive Officer being found responsible for the accounting error leading to an Accounting Restatement. In the event of an Accounting Restatement, the Company shall satisfy the Company's obligations under this Policy to recover any amount owed from any applicable Executive Officer by exercising its sole and absolute discretion in how to accomplish such recovery, to the extent permitted under Applicable Law and in compliance with (or pursuant to an exemption from the application of) Applicable Law, including Section 409A of the Code. The Company's recovery obligation pursuant to this Section 4 shall not apply to the extent that the Committee, or in the absence of the Committee, a majority of the independent directors serving on the Board, determines that such recovery would be impracticable and:

a. The direct expense paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered. Before concluding that it would be impracticable to recover any amount of Erroneously Awarded Compensation based on expense of enforcement, the Company must make a reasonable attempt to recover such Erroneously Awarded Compensation, document such reasonable attempt(s) to recover, and provide that documentation to the Stock Exchange;

b. Recovery would violate the laws of Alberta or the laws of Canada applicable therein, where that law was adopted prior to November 28, 2022. Before concluding that it would be impracticable to recover any amount of Erroneously Awarded Compensation based on violation of such law, the Company must obtain an opinion of Canadian counsel, acceptable to the Stock Exchange, that recovery would result in such a violation, and must provide such opinion to the Stock Exchange; or

c. Recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the registrant, to fail to meet the requirements of Applicable Law, including Section 401(a)(13) or Section 411(a) of the Code.

Prohibition on Indemnification and Insurance Reimbursement

The Company is prohibited from indemnifying any Executive Officer or former Executive Officer against the loss of Erroneously Awarded Compensation. Further, the Company is prohibited from paying or reimbursing an Executive Officer for purchasing insurance to cover any such loss.

Required Policy Related Filings

The Company shall file all disclosures with respect to this Policy in accordance with the requirements of the provincial and U.S. federal securities laws, including disclosures required by U.S. Securities and Exchange Commission filings.

Definitions

a. “Accounting Restatement” means an accounting restatement due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements, or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period.

b. “Accounting Restatement Date” means the earlier to occur of: (i) the date the Board, a committee of the Board, or the officer or officers of the Company authorized to take such action if the Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an Accounting Restatement; and (ii) the date a court, regulator, or other legally authorized body directs the Company to prepare an Accounting Restatement.

c. “Board” means the board of directors of the Company.

d. “Code” means the U.S. Internal Revenue Code of 1986, as amended. Any reference to a section of the Code or regulation thereunder includes such section or regulation, any valid regulation or other official guidance promulgated under such section, and any comparable provision of any future legislation or regulation amending, supplementing, or superseding such section or regulation.

e. “Erroneously Awarded Compensation” means, in the event of an Accounting Restatement, the amount of Incentive-Based Compensation previously received that exceeds the amount of Incentive-Based Compensation that otherwise would have been received had it been determined based on the restated amounts in such Accounting Restatement, and must be computed without regard to any taxes paid by the relevant Executive Officer; provided, however, that for Incentive-Based Compensation based on stock price or total stockholder return, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in an Accounting Restatement: (i) the amount of Erroneously Awarded Compensation must be based on a reasonable estimate of the effect of the Accounting Restatement on the stock price or total stockholder return upon which the Incentive-Based Compensation was received; and (ii) the Company must maintain documentation of the determination of that reasonable estimate and provide such documentation to the Stock Exchange.

f. “Executive Officer” means the Company’s president, principal financial officer, principal accounting officer (or if there is no such accounting officer, the controller), any vice-president of the Company in charge of a principal business unit, division, or function (such as sales, administration, or finance), any other officer who performs a policy-making function, or any other person who performs similar policy-making functions for the Company. An executive officer of the Company’s parent or subsidiary is deemed an “Executive Officer” if the executive officer performs such policy making functions for the Company.

g. “Financial Reporting Measure” means any measure that is determined and presented in accordance with the accounting principles used in preparing the Company’s financial statements, and any measure that is derived wholly or in part from such measure; provided, however, that a Financial Reporting Measure is not required to be presented within the Company’s financial statements or included in a filing with the U.S. Securities and Exchange Commission to qualify as a “Financial Reporting Measure.” For purposes of this Policy, “Financial Reporting Measure” includes, but is not limited to, stock price and total stockholder return.

h. “Incentive-Based Compensation” means any compensation that is granted, earned, or vested based wholly or in part upon the attainment of a Financial Reporting Measure.

i. “Stock Exchange” means the U.S. national stock exchange on which the Company’s Common Shares are listed (e.g., NYSE).

Acknowledgement

Each Executive Officer shall acknowledge and confirm annually that such Executive Officer agrees to be bound by, and to comply with, the terms and conditions of this Policy.

Severability

The provisions in this Policy are intended to be applied to the fullest extent of the law, such provision shall be applied to the maximum extent permitted, and shall automatically be deemed amended in a manner consistent with its objectives to the extent necessary to conform to any limitations required under applicable law.

Amendment, Termination

The Board may amend this Policy from time to time in its sole and absolute discretion and shall amend this Policy as it deems necessary to reflect Applicable Law, or to comply with (or maintain an exemption from the application of) Applicable Law, including Section 409A of the Code. The Board may terminate this Policy at any time.

Other Recovery Obligations, General Rights

To the extent that the application of this Policy would provide for recovery of Incentive-Based Compensation that the Company recovers pursuant to Section 304 of the Sarbanes-Oxley Act or other recovery obligations, the amount the relevant Executive Officer has already reimbursed the Company will be credited to the required recovery under this Policy. This Policy shall not limit the rights of the Company to take any other actions or pursue other remedies that the Company may deem appropriate under the circumstances and under Applicable Law, in each case to the extent permitted under Applicable Law and in compliance with (or pursuant to an exemption from the application of) Applicable Law, including Section 409A of the Code. For greater certainty, any Incentive-Based Compensation, or any other compensation, paid or payable to an employee, contractor or member of the Board pursuant to any agreement or arrangement with the Company (including under the Company’s existing Restricted Share Unit Plan, Deferred Share Unit Plan, Performance Share Unit Plan, Employee Share Value Plan or Stock Option Plan) which is subject to recovery under Applicable Law, will be subject to such deductions and clawback (recovery) as may be required to be made pursuant to Applicable Law (or any policy of the Company adopted pursuant to Applicable Law). Nothing contained in this Policy shall limit the Company’s ability to seek recoupment, in appropriate circumstances (including circumstances beyond the scope of this Policy) and as permitted by Applicable Law, of any amounts from any individual, in each case to the extent permitted under Applicable Law, including in compliance with (or pursuant to an exemption from the application of) Section 409A of the Code.

Conduct Detrimental to the Company

In addition, if the Board determines, acting reasonably, that an employee, contractor or member of the Board has engaged in conduct that is sufficiently detrimental to the Company, either during or after the cessation of such person's employment with, or service to, the Company, the Board may, at its sole election, terminate any Incentive-Based Compensation payable to such person that has not yet vested or that has not yet been paid. Detrimental conduct includes, but is not limited to, participating in transactions involving the Company and its clients which were under way, contemplated or under consideration at the time of termination, solicitation of clients or employees, disclosing confidential information, making inappropriate or defamatory comments about the Company or breaches of the material provisions of any of the Company's internal policies, including its Code of Conduct.

Successors

This Policy is binding and enforceable against all Executive Officers and their beneficiaries, heirs, executors, administrators or other legal representatives.

Exhibit 99.1



VEREN INC.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2024

Dated February 26, 2025

Contents

Section	Page
SPECIAL NOTES TO READER	1
GLOSSARY	5
SELECTED ABBREVIATIONS	7
CURRENCY OF INFORMATION	8
OUR ORGANIZATIONAL STRUCTURE	8
GENERAL DEVELOPMENT OF THE BUSINESS OF THE CORPORATION	9
DESCRIPTION OF OUR BUSINESS	11
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	14
ADDITIONAL INFORMATION RESPECTING VEREN	33
INDUSTRY CONDITIONS	44
RISK FACTORS	58
DIVIDENDS AND SHARE REPURCHASES	54
MARKET FOR SECURITIES	55
CONFLICTS OF INTEREST	57
LEGAL PROCEEDINGS	57
AUDIT COMMITTEE	73
TRANSFER AGENT AND REGISTRARS	75
AUDITOR	75
MATERIAL CONTRACTS	76
INTERESTS OF EXPERTS	76
ADDITIONAL INFORMATION	77

APPENDIX A - AUDIT COMMITTEE MANDATE
APPENDIX B - RESERVES COMMITTEE MANDATE
APPENDIX C - REPORTS ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR
APPENDIX D - REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

SPECIAL NOTES TO READER

Any "financial outlook" or "future-oriented financial information," in this AIF (as defined herein), as defined by applicable securities legislation, has been approved by management of Veren (as defined herein). Such financial outlook or future-oriented financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

This AIF and other reports and filings made with the securities regulatory authorities include certain statements that constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, Section 21E of the Securities Exchange Act of 1934 and the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" for the purposes of Canadian securities regulation (collectively, "forward-looking statements"). All forward-looking statements are based on our beliefs and assumptions based on information available at the time the assumption was made. Veren has tried to identify such forward-looking statements by use of such words as "could", "should", "can", "anticipate", "expect", "believe", "will", "may", "plan", "forecast", "intend", "projected", "sustain", "continues", "strategy", "potential", "grow", "estimate" and similar expressions, but these words are not the exclusive means of identifying such statements. These forward-looking statements are neither historical facts nor assurances of future performance, and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Veren believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements speak only as of the date of this AIF or, if applicable, as of the date specified in this AIF.

In particular, this AIF contains forward-looking statements pertaining, among other things, to the following:

- corporate strategy and anticipated financial and operational performance;
- forecast prices and the expected impact of commodity price fluctuations on cash available to pay dividends and return capital to shareholders;
- return of capital framework that targets the return of 60% of Veren's excess cash flow;
- hedging strategy, including expected outcomes, and the approach to managing physical delivery contracts;
- risk mitigation strategy and the expected outcomes;
- the potential impact of competition and our working relationships with industry partners and joint operators on Veren's business;
- business prospects;
- the performance characteristics of Veren's oil and natural gas properties, including but not limited to oil and natural gas production levels;
- anticipated future cash flows and oil and natural gas production levels;
- projected returns and exploration potential of our assets;
- the potential of Veren's plays;
- future development plans, including focus areas;
- forecast costs and expenses associated with Veren's business, including capital expenditure programs and how they will be funded;
- leverage objectives;
- credit ratings;
- corporate and asset acquisitions and dispositions;
- work commitments and drilling programs;
- expected location inventory development timing;
- expected production breakdown by area on a Proved and Proved plus Probable production basis;
- expected development timeframe of the Proved and Proved plus Probable locations;
- the quantity of oil and natural gas reserves;
- projections of commodity prices and costs;
- Veren's decline mitigation efforts;
- future enhanced oil recovery and waterflood programs;
- the possible impacts of curtailment on Veren;
- the impacts of the Redwater decision and other legal decisions;
- expected decommissioning, abandonment, remediation and reclamation costs;
- Veren's tax horizon;
- the impact of the Canada-United States-Mexico Agreement and expected timing for renegotiation;

- expected trends in environmental regulation, including the anticipated impact the trends may have on operations and compliance costs;
- the impact, and projected long-term impacts, of the pricing of carbon and greenhouse gases;
- payment of dividends, including special dividends, and the repurchase of Common Shares (as defined herein) by Veren, including pursuant to its normal course issuer bid;
- supply and demand for oil and natural gas;
- the actions of OPEC+;
- expectations of legal and regulatory changes and implementations and change in governmental and regulatory bodies;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes, including royalty regimes applicable to natural resources;
- stock option intentions;
- the impacts of the wars in Ukraine and the Middle East;
- the impacts of pandemics;
- the risks and impacts of droughts and wildfires;
- risks related to the regulatory, social and market efforts to address climate change; and
- such other factors as discussed throughout the "Risk Factors" section of this AIF.

By their nature, such forward-looking statements are subject to a number of risks, uncertainties and assumptions, which could cause actual results or other expectations to differ materially from those anticipated, expressed or implied by such statements, including those material risks discussed in our Management's Discussion and Analysis for the year ended December 31, 2024, under the headings "Risk Factors" and "Forward-Looking Information" and as disclosed in this AIF. The material assumptions and factors in making forward-looking statements are disclosed in the Management's Discussion and Analysis for the year ended December 31, 2024, under the headings "Overview," "Development Capital Expenditures," "Commodity Derivatives," "Liquidity and Capital Resources," "Critical Accounting Estimates," "Risk Factors," "Changes in Accounting Policies" and "Guidance".

This information contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Veren's control. Such risks and uncertainties include, but are not limited to: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations, pipeline restrictions and blowouts; the impacts of U.S. and Canadian tariffs; the impacts of the wars in Ukraine and the Middle East; the actions of OPEC+; the risk of carrying out operations with minimal environmental impact; industry conditions, including changes in laws and regulations, the adoption of new environmental laws and regulations, and changes in how environmental laws and regulations are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs and of dispositions and monetization; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; the impacts of pandemics, drought and wildfires; fluctuations in foreign exchange and interest rates; stock market volatility; failure to realize the anticipated benefits of acquisitions and dispositions; general economic, market and business conditions; inflation; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; tax laws and changes thereto, crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the control of Veren, including those listed under "Risk Factors" in this AIF. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as each of these are interdependent and Veren's future course of action depends on management's assessment of all information available at the relevant time.

Statements relating to "reserves" and "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Actual reserve values may be greater than or less than the estimates provided herein.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable crude oil, natural gas and natural gas liquids reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable 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 associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Veren's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. In addition, the discounted and undiscounted net present value of future net revenues attributable to reserves do not represent fair market value; and the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Veren's actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits, if any, Veren will derive therefrom.

Barrels of oil equivalent ("**boe**") may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Netback received is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses. Netback received excludes realized commodity derivative gains and losses. Netback received is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis. Netback received is equivalent to "operating netback" referenced in the MD&A. The calculation of netback received is shown in the Production History section of this AIF.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for the year.

Additional information on these and other factors that could affect Veren's operations or financial results are included in Veren's reports on file with Canadian and U.S. securities regulatory authorities (including our Annual Report on Form 40-F and Management's Discussion and Analysis). Readers are cautioned not to place undue reliance on the forward-looking information, which is given as of the date it is expressed in this AIF or otherwise. We do not undertake any obligation to publicly update or revise any forward-looking statements, whether due to new information, future events or otherwise, except as required pursuant to applicable law. All subsequent forward-looking statements, whether written or oral, attributable to Veren or persons acting on the Corporation's behalf are expressly qualified in their entirety by these cautionary statements.

Credit Ratings

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

Currency Presentation

All references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated. The daily rate of exchange on December 31, 2024, as reported by the Bank of Canada for the conversion of Canadian dollars into United States dollars was Cdn$1.00 equals US$0.6950 and for the conversion of United States dollars into Canadian dollars was US$1.00 equals Cdn$1.4389. The following table sets forth the high, low and average of the daily exchange rates for the years ended December 31, 2024 and 2023, respectively, each for one United States dollar expressed in Canadian dollars as reported by the Bank of Canada.

	Year ended December 31, 2024 (Cdn$/US$)	Year ended December 31, 2023 (Cdn$/US$)
High	0.7510	0.7617
Low	0.6937	0.7207
Average	0.7302	0.7410

Presentation of our Reserve and Resource Information

Current SEC (as defined herein) reporting requirements permit oil and gas companies to disclose Probable reserves (as defined herein), in addition to the required disclosure of Proved reserves. Under current SEC requirements, net quantities of Proved and Probable reserves are required to be disclosed, which requires disclosure on an after-royalties basis and does not include reserves relating to the interests of others. For a description of these and additional differences between Canadian and U.S. standards of reporting reserves, see "*Risk Factors — Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States.*"

New York Stock Exchange

As a Canadian corporation listed on the NYSE (as defined herein), we are not required to comply with most of the NYSE's corporate governance standards and, instead, may comply with Canadian corporate governance practices. We are, however, required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. Except as summarized on our website at www.vrn.com, we are in compliance with the NYSE corporate governance standards.

GLOSSARY

In this AIF, the capitalized terms set forth below have the following meanings:

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

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

"**Alberta EPA**" means the Alberta Ministry of Environment and Protected Areas.

"**AIF**" means this annual information form of the Corporation dated February 26, 2025 for the year ended December 31, 2024.

"**Board**" or "**Board of Directors**" means the board of directors of the Corporation.

"**Common Shares**" means common shares in the capital of the Corporation.

"**Conversion Arrangement**" means the plan of arrangement under Section 193 of the ABCA, completed on July 2, 2009 pursuant to which the Trust effectively converted from an income trust to a corporate structure.

"**CPUSH**" means Crescent Point U.S. Holdings Corp.

"**DRIP**" means the Premium Dividend™ and Dividend Reinvestment Plan of the Corporation.

"**DSU Plan**" means the Deferred Share Unit Plan of the Corporation.

"**ESVP**" means the Employee Share Value Plan of the Corporation.

"**Greenhouse Gases**" or "**GHGs**" means any or all of, including but not limited to, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6).

"**HEI**" means Hammerhead Energy Inc.

"**HRULC**" means Hammerhead Resources ULC.

"**IFRS**" means the standards and interpretations adopted by the International Accounting Standards Board, as amended from time to time.

"**McDaniel**" means McDaniel & Associates Consultants Ltd.

"**MD&A**" means the management's discussion and analysis of financial condition and results of operations of the Corporation for the year ended December 31, 2024.

"**NCIB**" means normal course issuer bid.

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

"**NYSE**" means the New York Stock Exchange.

"**OPEC+**" means the Organization of the Petroleum Exporting Countries and cooperating oil-exporting nations.

"**Partnership**" means Veren Partnership, a general partnership formed under the laws of the Province of Alberta, having VHL and the Corporation as partners.

"**PSU Plan**" means the Performance Share Unit Plan of the Corporation.

"**Restricted Share Bonus Plan**" means the Restricted Share Bonus Plan of the Corporation.

"**SDP**" means the Share Dividend Plan of the Corporation.

"**SEC**" means the U.S. Securities and Exchange Commission.

"**Shareholders**" means the holders from time to time of Common Shares.

"**Stock Option Plan**" means the Stock Option Plan of the Corporation.

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5th Supp.), and the regulations promulgated thereunder, each as amended from time to time.

"**Trust**" means Crescent Point Energy Trust, an unincorporated open ended investment trust governed by the laws of the Province of Alberta that was dissolved pursuant to the Conversion Arrangement.

"**Trust Units**" means the trust units of the Trust.

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

"**U.S.**" means the United States of America.

"**Unitholders**" means holders of Trust Units.

"**Veren**" or the "**Corporation**" means Veren Inc., formerly Crescent Point Energy Corp., a corporation amalgamated under the ABCA and, where applicable, includes its subsidiaries and affiliates.

"**VERUS**" means Veren U.S. Corp.

"**VHL**" means Veren Holdings Ltd.

For additional definitions used in this AIF, please see "Statement of Reserves Data and Other Oil and Gas Information-Notes and Definitions".

SELECTED ABBREVIATIONS

In this AIF, the abbreviations set forth below have the following meanings:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls	barrels	Mcf/d	thousand cubic feet per day
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls	thousand barrels	MMcf/d	million cubic feet per day
NGLs	natural gas liquids	MMBTU	million British Thermal Units
		MMBTU/d	million British Thermal Units per day
		Mcfe	thousand cubic feet of gas equivalent converting one barrel of oil to 6 Mcf of natural gas equivalent

Other	
AECO	the natural gas storage facility located at Suffield, Alberta
boe or BOE	barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
boe/d	barrel of oil equivalent per day
m^3	cubic metres
M$	thousand dollars
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
MM$	million dollars
NYMEX	New York Mercantile Exchange natural gas price
tCO2e/boe	tonnes of carbon dioxide equivalent per barrel of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CURRENCY OF INFORMATION

The information set out in this AIF is stated as at December 31, 2024, unless otherwise indicated. Capitalized terms used but not defined in the text are defined in the Glossary.

OUR ORGANIZATIONAL STRUCTURE

The Corporation

Veren Inc. ("**Veren**" or the "**Corporation**" and, together with its direct and indirect subsidiaries and partnerships, where appropriate, "**we**", "**our**" or "**us**") is a corporation formed by the amalgamation of Veren and HRULC under the ABCA following Veren's acquisition of HEI and its subsidiary, HRULC. The Corporation changed its name from Crescent Point Energy Corp. to Veren Inc. on May 10, 2024. Veren is the successor to Crescent Point Energy Ltd. which was founded in 2001, and to the Trust, following the completion of the "conversion" of the Trust from an income trust to a corporate structure in accordance with the Conversion Agreement.

The head and principal office of the Corporation is located at Suite 2000, 585 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1 and its registered office is located at Suite 3700, 400 – 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

The Corporation is a conventional oil and gas producer with assets strategically focused in properties comprised of high quality, long life, operated, light and medium crude oil, natural gas liquids and natural gas reserves in Western Canada. We make regular cash dividends to Shareholders from our net cash flow.

Partnership

The Partnership is a general partnership governed by the laws of the Province of Alberta. As set forth in the diagram below under "*Organizational Structure of the Corporation*", the partners of the Partnership are VHL and the Corporation.

The existing business of the Corporation is carried on through the Partnership and through VERUS. The Partnership holds all the Corporation's Canadian operating assets and VERUS holds all of the Corporation's U.S. assets.

VHL

VHL is a wholly owned subsidiary of the Corporation. VHL is a partner of the Partnership.

VERUS

VERUS is a wholly owned indirect subsidiary of the Corporation.

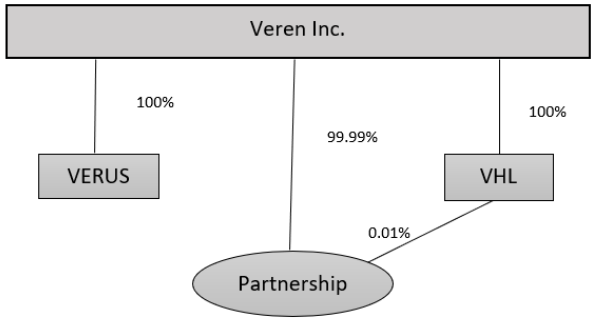
Relationships

The following table provides the name, the percentage of voting securities owned by the Corporation and the jurisdiction of incorporation, continuance or formation of the Corporation's material subsidiaries as at the date hereof.

	Percentage of Voting Securities (Directly or Indirectly)	Jurisdiction of Incorporation/Formation
VHL	100%	Alberta
Partnership	100%	Alberta
VERUS	100%	Delaware

Organizational Structure of the Corporation

The following diagram describes the inter-corporate relationships among the Corporation and its material direct and indirect subsidiaries described above as at December 31, 2024 and current to February 26, 2025. Reference should be made to the appropriate sections of this AIF for a complete description of the structure of the Corporation.



HEI has been wound-up but not yet dissolved.

GENERAL DEVELOPMENT OF THE BUSINESS OF THE CORPORATION

History

The following is a description of the general development of the business of Veren over the past three years.

2022

On March 4, 2022, the Corporation announced the approval by the TSX of its notice to implement a NCIB (the **2022 NCIB**") to purchase, for cancellation, up to 57,309,975 Common Shares, or ten percent of the Corporation's public float, as at February 28, 2022. The NCIB commenced on March 9, 2022 and expired on March 8, 2023. In 2022, the Corporation purchased a total of 31,347,100 Common Shares under its NCIB programs.

On May 12, 2022, the Corporation announced that it was increasing its quarterly dividend from $0.045 per share payable every quarter to $0.065 per share payable every quarter, commencing with the second quarter of 2022.

On May 19, 2022, Mindy Wight was elected to the Board. See "*Additional Information Respecting Veren - Directors and Officers*".

On October 26, 2022, the Corporation announced a special dividend of $0.035 per share payable on November 14, 2022.

On December 9, 2022, the Corporation announced that it was increasing its quarterly dividend from $0.065 per share payable every quarter to $0.10 per share payable every quarter, commencing with the first quarter of 2023.

2023

On January 11, 2023, the Corporation completed the acquisition of certain Kaybob Duvernay assets in Alberta for cash consideration of $370.4 million, including closing adjustments.

On March 2, 2023, the Corporation announced a special dividend of $0.032 per share payable on March 17, 2023.

On March 7, 2023, the Corporation announced the approval by the TSX of its notice to implement a NCIB (the **2023 NCIB**") to purchase, for cancellation, up to 54,605,659 Common Shares, or ten percent of the Corporation's public float, as at February 23, 2023. The NCIB commenced on March 9, 2023 and is due to expire on March 8, 2024. In 2023, the Corporation purchased a total of 34,611,900 Common Shares under its NCIB programs.

On March 28, 2023, the Corporation entered into an agreement with Spartan Delta Corp. (**Spartan Delta**") to acquire Spartan Delta's Montney assets in Alberta for cash consideration of $1.7 billion. Cash consideration was funded through the Corporation's existing credit facility. The acquisition closed on May 10, 2023.

On May 10, 2023, concurrent with the closing of the Spartan Delta acquisition, the Company entered into the Syndicated Liquidity Facility (as defined below) with ten banks that matures on May 10, 2025.

On July 26, 2023, the Corporation announced a special dividend of $0.035 per share payable on August 15, 2023.

On August 24, 2023, Veren entered into an agreement with a private operator to sell substantially all its North Dakota assets for US$432.7 million including closing adjustments and US$60.0 million of deferred consideration. The acquisition closed on October 24, 2023. Following completion of the acquisition, Veren ceased to hold any operating assets in the United States.

On November 2, 2023, the Corporation announced a special dividend of $0.02 per share payable on November 22, 2023.

On November 6, 2023, Veren announced that it entered into an arrangement agreement to acquire, by a statutory arrangement, HEI, and its subsidiary, HRULC, for total consideration of approximately $2.52 billion (the "**Hammerhead Acquisition**"). The consideration included $1.54 billion in cash, the issuance of 53.2 million Common Shares and $480.2 million of net debt.

On November 6, 2023, Veren announced that it entered into an agreement with a syndicate of underwriters co-led by BMO Capital Markets and RBC Capital Markets (collectively the "**Underwriters**") under which the Underwriters agreed to purchase, on a bought deal basis 48,550,000 Common Shares at $10.30 per common share for aggregate gross proceeds of approximately $500 million (the "**Offering**"). The Offering closed on November 10, 2023.

On December 21, 2023, Veren completed the Hammerhead Acquisition.

On December 21, 2023, concurrent with the closing of the Hammerhead Acquisition, the Company entered into the Term Loan (as defined below) with twelve banks that matures on November 26, 2026.

On December 31, 2023, HEI was wound-up into the Corporation.

CPUSH, a wholly owned direct subsidiary of the Corporation was dissolved effective December 31, 2023.

2024

On January 1, 2024, HRULC was amalgamated with Veren.

On January 26, 2024, the Corporation completed the disposition of its Southern Alberta assets for total consideration of approximately $37.1 million, including closing adjustments. Total consideration includes $25.0 million of deferred consideration receivables. Due to significant decommissioning liabilities associated with these assets, this transaction reduced the Company's decommissioning liability balance by $92.4 million.

On March 7, 2024, the Corporation announced the approval by the TSX of its notice to implement a NCIB (the **2024 NCIB**") to purchase, for cancellation, up to 61,663,522 Common Shares, or ten percent of the Corporation's public float, as at February 29, 2024. The NCIB commenced on March 11, 2024 and is due to expire on March 10, 2025. In 2024, the Corporation purchased a total of 10,429,500 Common Shares under its NCIB programs.

On May 6, 2024, the Corporation announced that it had entered into an agreement with Saturn Oil & Gas Inc. to sell certain non-core assets in Saskatchewan for approximately $531.6 million in cash, including closing adjustments. The transaction closed on June 14, 2024.

On May 10, 2024, the Shareholders approved an amendment to the Corporation's articles to change its name to Veren Inc.

On June 14, 2024, the Corporation received an investment grade BBB (low) rating with a stable trend from DBRS Limited.

On June 19, 2024, the Corporation announced an offering of $1.0 billion aggregate principal amount of senior unsecured notes, consisting of $550 million of 4.968% notes priced at par and due June 2029, and $450 million of 5.503% notes priced at par and due June 2034. The notes offering closed on June 21, 2024.

On September 9, 2024, the Corporation entered into a strategic long-term partnership with Pembina Gas Infrastructure, which included the sale of certain infrastructure assets in the Alberta Montney for net cash proceeds of $400 million. Veren closed the transaction on October 9, 2024 and applied the proceeds against bank indebtedness.

2025

On January 21, 2025, Corey Bieber and Jodi J. Jenson Labrie were appointed to the Board. See "Additional Information Respecting Veren - Directors and Officers".

DESCRIPTION OF OUR BUSINESS

General

The Corporation is an oil and gas exploration, development and production company. The Corporation is a conventional oil and gas producer with assets strategically focused in properties comprised of high quality, long life, operated, light and medium crude oil, natural gas liquids and natural gas reserves in Western Canada. The primary assets of the Corporation are currently its interest in the Partnership and shares in VHL.

The crude oil and natural gas properties and related assets generating income for the benefit of the Corporation are located in the provinces of Alberta and Saskatchewan. The properties and assets consist of producing crude oil, natural gas liquids and natural gas reserves and Proved plus Probable (as defined herein) crude oil, natural gas liquids and natural gas reserves not yet on production, and land holdings.

We pay regular cash dividends to Shareholders from our net cash flow in accordance with our dividend policy. Our primary sources of cash flow are distributions from the Partnership. During the year ended December 31, 2024, dividends declared to shareholders were $0.460 per Common Share. See "*Dividends*".

We also return capital to shareholders by making share repurchases with our net cash flow. The share repurchases are made in accordance with the terms of an approved and implemented Normal Course Issuer Bid. See *"Share Repurchases*".

Strategy

Our strategy is to deliver lasting market-leading value to our stakeholders as a trusted, ethical and environmentally responsible source for energy. We will maintain a resilient, balanced and sustainable portfolio, and apply our agile, diverse, learning mindset to optimize all aspects of our business.

We strive to enhance shareholder returns by cost effectively developing a focused asset base in a responsible and sustainable manner. The Corporation employs a disciplined capital allocation framework centered around returns and balance sheet strength, in order to create value for shareholders through a combination of significant return of capital, returns-based growth and balance sheet strength.

We strategically develop our properties through detailed technical analysis including reservoir characteristics, petroleum initially in place, recovery factors and the applicability of enhanced recovery techniques. Our development strategies include, multi-stage fracture stimulation of horizontal wells, infill and step-out wells, re-completion of existing wells along with the application of secondary and enhanced oil recovery techniques, including waterflood programs.

Risk Management and Marketing

Factors outside our control impact, to varying degrees, the prices we receive for production. These include, but are not limited to:

(a) world market forces, including world supply and consumption levels and the ability of OPEC+ and others to set and maintain production levels and prices for crude oil;
(b) political conditions, including the risk of hostilities in the Middle East, South America, Eastern Europe and other regions throughout the world;
(c) availability, proximity and capacity of take-away alternatives, including oil and gas gathering systems, pipelines, processing facilities, railcars and railcar loading facilities;
(d) increases or decreases in crude oil differentials and their implications for prices received by us;
(e) the impact of changes in the exchange rate between Canadian and U.S. dollars on prices received by us for our crude oil and natural gas;
(f) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the prices of crude oil and natural gas;
(g) global and domestic economic and weather conditions and changes in demand as a result of outbreaks, pandemics, or other health emergencies;
(h) U.S. and Canadian policy, including tax, tariff and climate;
(i) price and availability of alternative energy sources; and
(j) the effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, differentials and foreign exchange and interest rates, equity price, among other factors, are outside of our control and yet can have a significant impact on the level of cash we have available for return of capital to our shareholders, including payment of dividends and the repurchase of Common Shares.

To mitigate a portion of these risks, we actively initiate, manage and disclose the effects of our hedging activities. Our strategy for crude oil and natural gas production is to hedge up to 65%, or as otherwise approved by the Board of Directors, of our net of royalty production up to a rolling three-and-a-half-year basis, at the discretion of management. The Corporation also uses a combination of financial derivatives and fixed-differential physical contracts to hedge price differentials. For oil differential hedging, Veren's risk management program allows for hedging a forward profile of up to three and a half years, and up to 35% net of royalty production. For gas differential hedging, Veren's risk management program allows for hedging a forward profile of up to three and a half years, and up to 50% net of royalty production. All hedging activities are governed by our Risk Management and Counterparty Credit Policy and are regularly reviewed by the Board of Directors.

As part of our risk management program, benchmark oil prices are hedged using financial WTI-based instruments transacted in Canadian and U.S. dollars, benchmark natural gas prices are hedged using financial AECO and NYMEX based instruments transacted in Canadian and U.S. dollars, respectively. Veren also enters into physical delivery and derivative WTI price differential contracts which manage the spread between US$ WTI and various stream prices on a portion of its production. The Corporation manages physical delivery contracts on a month-to-month spot and term contract basis. From January to December 2024, approximately 2,000 bbls/d of liquids production was contracted with fixed price differentials off WTI. Veren also enters into derivative NYMEX price differential contracts which manage the spread between US$ NYMEX and AECO-based pricing on a portion of its natural gas production. From January to December 2024, the Company had approximately 80,500 MMBTU/d of natural gas financial derivatives with fixed price differentials off NYMEX.The Corporation recorded an aggregate realized derivative gain on crude oil, NGL and natural gas hedge contracts of $71.8 million in 2024.

Refer to the annual financial statements for our commitments under all hedging agreements as at December 31, 202.

In addition to hedging benchmark crude oil and natural gas prices with financial instruments, we also may mitigate crude oil basis risk by delivering a portion of our crude oil production into diversified refinery markets using rail transportation when it is economically beneficial to do so. Veren operates two railcar loading facilities, serving its key producing areas of southeast Saskatchewan and southwest Saskatchewan. Crude oil and NGL volumes loaded at these facilities are sold at the loading facilities and our buyers are responsible for providing railcars and managing transportation logistics from that point until delivery.

We mitigate credit risk by having a well-diversified marketing portfolio for our commodity sales. Credit risk associated with the Corporation's product sales and with the Corporation's financial hedging portfolio is managed by Veren's Risk Management Committee and is governed by a Board-approved Risk Management and Counterparty Credit Policy that is reviewed biennially by the Board of Directors. The Policy requires annual credit reviews of all trade counterparties. Credit limits are required to be set for all trade counterparties, which are based on either a fixed dollar amount which is set annually, at a minimum, or a percentage of the Corporation's portfolio calculated monthly. Veren utilizes a diversified approach in both its physical sales portfolio and its financial hedging portfolio. The physical sales portfolio consists of 84 purchasers and its financial hedging portfolio consists of approximately 12 counterparties. The Corporation's portfolio of counterparty exposures is monitored on a monthly basis.

To further mitigate credit risk associated with its physical sales portfolio, Veren may obtain financial assurances such as parental guarantees, prepayments, letters of credit and third-party credit insurance. Including these assurances, approximately 98% of the Corporation's oil and gas sales are with entities considered investment grade.

Revenue Sources

Our liquids and natural gas volumes are produced in Alberta and Saskatchewan. During 2024, approximately 62% of our liquids volumes were produced in Alberta and 38% in Saskatchewan. Approximately, 95% of our natural gas volumes were produced in Alberta and 5% in Saskatchewan. The Corporation sells a portion of its Canadian natural gas production into U.S. pricing markets through VERUS.

For 2024, our commodity production mix was approximately 37% tight oil, 34% shale gas, 23% NGLs, 5% light and medium oil, and 1% heavy oil.

The following table summarizes our revenue sources by product before hedging and royalties:

For Year Ended	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs[(1)]	Shale Gas	Conventional Natural Gas
2024	6.5%	1.1%	57.5%	28.0%	6.8%	0.1%
2023	10.5%	2.6%	55.9%	24.9%	5.8%	0.3%
2022	13.2%	3.2%	51.1%	24.9%	7.1%	0.5%

Notes:
(1) Within our NGL mix, approximately 80% of our 2024 revenue came from condensate sales (2023 - 80%, 2022 - 75%).

Competition

We actively compete for reserve acquisitions, exploration leases, licenses and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than we do. Our competitors include major integrated oil and natural gas companies, numerous other independent oil and natural gas entities and individual producers and operators. Similarly, we face a competitive market when we attempt to divest of non-core assets.

Certain of our customers and potential customers are themselves exploring for crude oil and natural gas, and the results of such exploration efforts could affect our ability to sell or supply crude oil or natural gas to these customers in the future. Our ability to successfully bid on and acquire additional property rights, divest property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers is dependent upon developing and maintaining close working relationships with our industry partners and joint operators, our ability to select and evaluate suitable properties, and our ability to consummate transactions in a highly competitive environment.

Seasonal Factors

The production of crude oil and natural gas is dependent on access to areas where development of reserves is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

Personnel

As of December 31, 2024, the Corporation had 746 permanent employees: 404 employees at the head office in Calgary and 342 field employees.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

In accordance with NI 51-101, the reserves data of the Corporation set forth below (the **Reserves Data**") is based upon evaluations conducted by McDaniel with an effective date of December 31, 2024 (the "**Veren Reserve Report**"). The tables below are a combined summary of our crude oil, natural gas liquids, and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Veren Reserve Report based on January 1, 2025, forecast price and cost assumptions using the average of three Independent Reserve Evaluators (McDaniel, GLJ Ltd. and Sproule Associates Ltd.). McDaniel evaluated the Corporation's total Proved plus Probable reserves and total Proved plus Probable value discounted at 10% and evaluated all of the Corporation's properties to prepare the Veren Reserve Report. The tables below summarize the data contained in the Veren Reserve Report.

The net present value of future net revenue attributable to our reserves is stated without provision for interest costs, and general and administrative costs, but after providing for estimated royalties, production costs, capital taxes, development costs, other income, future capital expenditures, projected carbon emission costs, and well and location abandonment costs. The reserve assessments also include costs associated with wells that have not been assessed values in the reserve reports and facilities and gathering systems associated with the ongoing production for the Corporation. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to our reserves estimated by McDaniel represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of our crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

The Corporation continuously monitors and reviews legislation concerning greenhouse gas emissions and the impact on operations. Legislation adopted in 2019 has allowed Veren to reduce anticipated negative financial impacts from the production of oil and gas products through the Output-Based Performance Standard ("**OBPS**") program in Saskatchewan and the Technology Innovation and Emission Reduction ("**TIER**") program in Alberta. The carbon emission costs related to government programs are fully integrated into the operating costs and capital unit costs in the reserve evaluation.

The Veren Reserve Report includes the abandonment, decommissioning, and reclamation costs for both the active and inactive locations, including all non-producing and suspended wells, facilities and pipelines. The incremental liabilities from the inactive locations on the total Proved plus Probable reserves is estimated at $153 million of value discounted at 10%. The total impact in the Veren Reserve Report from the combined active and inactive liabilities on total Proved plus Probable reserves is estimated at $256 million of value discounted at 10%.

The Veren Reserve Report is based on certain factual data supplied by Veren as well as McDaniel's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to Veren's petroleum properties and contracts were supplied by the Corporation to McDaniel, and were accepted without any further investigation. McDaniel accepted this data as presented and neither title searches, nor field inspections were conducted.

Reserves Data – Forecast Prices and Costs

Summary of Oil and Gas Reserves[1]

	Light and Medium Crude Oil		Heavy Crude Oil		Tight Oil		Natural Gas Liquids	
Reserves Category	Gross *(Mbbls)*	Net *(Mbbls)*	Gross *(Mbbls)*	Net *(Mbbls)*	Gross *(Mbbls)*	Net *(Mbbls)*	Gross *(Mbbls)*	Net *(Mbbls)*
Proved Developed Producing	18,255	16,354	—	—	126,863	112,186	78,826	66,626
Proved Developed Non-Producing	173	159	—	—	1,074	990	261	225
Proved Undeveloped	2,038	1,905	—	—	112,787	95,668	107,985	91,557
Total Proved	20,465	18,418	—	—	240,724	208,844	187,072	158,408
Total Probable	8,025	7,059	—	—	139,147	116,479	89,436	69,176
Total Proved Plus Probable	28,490	25,477	—	—	379,871	325,324	276,508	227,584

	Shale Gas		Conventional Natural Gas		Total	
Reserves Category	Gross (*MMcf*)	Net (*MMcf*)	Gross (*MMcf*)	Net (*MMcf*)	Gross[2] *(Mboe)*	Net[3] *(Mboe)*
Proved Developed Producing	647,859	600,392	6,969	7,504	333,081	296,482
Proved Developed Non-Producing	4,265	4,044	55	45	2,228	2,056
Proved Undeveloped	1,085,252	998,818	679	601	403,798	355,700
Total Proved	1,737,377	1,603,253	7,702	8,151	739,108	654,238
Total Probable	942,653	844,743	3,145	3,101	394,241	334,022
Total Proved Plus Probable	2,680,030	2,447,996	10,848	11,252	1,133,349	988,260

Notes:
(1) Numbers may not add due to rounding.
(2) Gross reserves are working interest reserves before royalty deductions.
(3) Net reserves are working interest reserves after royalty deductions plus royalty interest reserves.

Net Present Value of Future Net Revenue of Oil and Gas Reserves[1]

	Before Income Taxes Discounted at (%/year)						After Income Taxes Discounted at (%/year)					
Reserves Category	0% (MM$)	5% (MM$)	8% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	8% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
Proved Developed Producing	8,174	6,866	6,209	5,841	5,113	4,579	7,067	5,991	5,430	5,114	4,488	4,029
Proved Developed Non-Producing	50	43	39	37	33	29	43	37	34	32	28	26
Proved Undeveloped	7,260	5,002	4,055	3,542	2,557	1,866	6,066	4,149	3,345	2,911	2,079	1,499
Total Proved	15,484	11,910	10,303	9,420	7,702	6,474	13,176	10,176	8,809	8,057	6,596	5,554
Total Probable	11,813	7,023	5,408	4,620	3,265	2,431	9,052	5,307	4,055	3,447	2,407	1,773
Total Proved Plus Probable	27,298	18,934	15,711	14,040	10,967	8,904	22,228	15,483	12,864	11,504	9,003	7,327

Notes:
(1) Numbers may not add due to rounding.

Additional Information Concerning Future Net Revenue – (Undiscounted)[1]

Reserves Category	Revenue (MM$)	Royalties & Burdens[2] (MM$)	Operating Costs (MM$)	Development Costs (MM$)	Abandonment and Reclamation Costs[3] (MM$)	Future Net Revenue Before Income Taxes (MM$)	Income Tax (MM$)	Future Net Revenue After Income Taxes (MM$)
Proved	46,817	6,277	16,994	6,586	1,476	15,484	2,308	13,176
Proved Plus Probable	74,572	11,101	25,322	9,186	1,665	27,298	5,070	22,228

Notes:
(1) Numbers may not add due to rounding.
(2) Saskatchewan Capital Resource Surcharge has been included under the royalties and burdens column.
(3) In accordance with the Canadian Oil and Gas Evaluation Handbook, abandonment and reclamation costs include: (i) entities with associated reserves included in the Veren Reserve Report, the undiscounted abandonment and reclamation costs associated with these amounts are $897 million and $1.09 billion for Proved and Proved plus Probable, respectively; and (ii) non-reserve entities that include wells with no reserves assigned, suspended wells, pipeline, and facilities, the undiscounted abandonment and reclamation costs associated with these are estimated at $579 million.

Future Net Revenue by Production Type[1]

	Future Net Revenue Before Income Taxes[2] (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	*(%)*	*($/boe)*	*($/Mcfe)*
Proved				
Light and Medium Crude Oil[3]	175	1.9	8.64	1.44
Heavy Crude Oil[3]	—	—	—	—
Tight Oil[5]	5,700	60.5	13.15	2.19
Shale Gas[4][6]	3,539	37.6	17.72	2.95
Conventional Natural Gas[4]	6	0.1	7.39	1.23
Total Proved	9,420	100	14.40	2.40

Notes:
(1) Numbers may not add due to rounding.
(2) Other company revenue and costs not related to a specific production type have been allocated proportionately to production types. Unit values are based on Company Net Reserves.
(3) Including solution gas and other by-products.
(4) Including by-products, but excluding solution gas.
(5) Including solution gas (categorized as "Shale Gas") and other by-products.
(6) Shale Gas includes the majority of Natural Gas Liquids.

	Future Net Revenue Before Income Taxes[2] (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	*(%)*	*($/boe)*	*($/Mcfe)*
Proved Plus Probable				
Light and Medium Crude Oil[3]	347	2.5	12.21	2.04
Heavy Crude Oil[3]	—	—	—	—
Tight Oil[5]	8,895	63.4	13.38	2.23
Shale Gas[4][6]	4,791	34.1	16.28	2.71
Conventional Natural Gas[4]	7	0.1	7.22	1.20
Total Proved Plus Probable	14,040	100	14.21	2.37

Notes:
(1) Numbers may not add due to rounding.
(2) Other company revenue and costs not related to a specific production type have been allocated proportionately to production types. Unit values are based on Company Net Reserves.
(3) Including solution gas and other by-products.
(4) Including by-products, but excluding solution gas.
(5) Including solution gas (categorized as "Shale Gas") and other by-products.
(6) Shale Gas includes the majority of Natural Gas Liquids.

Notes and Definitions

In the tables set forth above in "*Disclosure of Reserves Data*" and elsewhere in this AIF, the following notes and other definitions are applicable.

Reserve Categories

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of Proved and Probable reserves have been established in accordance with NI 51-101 to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

(a) "**Reserves**" are estimated remaining economic quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

(b) "**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.

(c) "**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.

(d) "**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.

(e) "**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 category (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

(f) **"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.

Levels of Certainty for Reported Reserves

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

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved reserves; and
- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

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

Additional Definitions

The following terms, used in the preparation of the Veren Reserve Report and this AIF, have the following meanings:

(a) "**associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

(b) "**crude oil**" or "**oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain small amounts of sulphur and other non-hydrocarbons, that exists in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. It does not include liquids obtained from the processing of natural gas.

(c) "**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(ii) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(iii) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds measuring devices and production storage, natural gas cycling and processing plants, and central utility and waste disposal system; and

(iv) provide improved recovery systems.

(d) "**development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

(e) "**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(ii) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;

(iii) dry hole contributions and bottom hole contributions;

(iv) costs of drilling and equipping exploratory wells; and

(v) costs of drilling exploratory type stratigraphic test wells.

(f) "**exploratory well**" means a well that is not a development well, a service well or a development type stratigraphic test well.

(g) "**field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

(h) "**future prices and costs**" means future prices and costs that are:

(i) generally accepted as being a reasonable outlook of the future; and

(ii) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (i).

(i) "**future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(i) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(ii) without deducting estimated future costs that are not deductible in computing taxable income;

(iii) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(iv) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year end statutory tax rates, taking into account future tax rates already legislated.

(j) "**future net revenue**" means the estimated net amount to be received with respect to the anticipated development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using future prices and costs.

(k) "**gross**" means:

(i) in relation to the Corporation's interest in production or reserves, its "company gross reserves", which are its working interest (operated or non-operated) share before deduction of royalties and without including any royalty interests of the Corporation;

(ii) in relation to wells, the total number of wells in which the Corporation has an interest; and

(iii) in relation to properties, the total area of properties in which the Corporation has an interest.

(l) "**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases.

(m) "**natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

(n) "**net**" means:

(i) in relation to the Corporation's interest in production or reserves, its working interest (operated or non-operated) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(ii) in relation to the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(iii) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

(o) "**non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

(p) "**operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities as well as other costs of operating and maintaining those wells and related equipment and facilities.

(q) "**production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

(r) "**property**" includes:

(i) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(ii) royalty interests, production payments payable in oil or gas, and other non-operated interests in properties operated by others; and

(iii) an agreement with a foreign government or authority under which the Corporation participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

(s) "**property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

(i) costs of lease bonuses and options to purchase or lease a property;

(ii) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee; and

(iii) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

(t) "**proved property**" means a property or part of a property to which reserves have been specifically attributed.

(u) "**reservoir**" means a subsurface rock unit that contains an accumulation of petroleum.

(v) "**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

(w) "**solution gas**" means natural gas dissolved in crude oil.

(x) "**stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) "exploratory type" if not drilled into a proved property; or (ii) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

(y) "**support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

(z) "**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

(aa) "**well abandonment and reclamation costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system and remediating and reclaiming the site to original conditions. They do not include costs of abandoning the gathering system.

Pricing Assumptions – Forecast Prices and Costs

The average of the three independent reserve evaluator price decks (McDaniel, GLJ Ltd. and Sproule Associates Ltd.) resulted in the following pricing, exchange rate and inflation rate assumptions as of January 1, 2025, in estimating our reserves data using forecast prices and costs.

Year	Crude Oil		Conventional Natural Gas		NGLs					
	WTI at Cushing Oklahoma *(US$/bbl)*	Edmonton *(Cdn$/bbl)*	Henry Hub NYMEX *(US$/MMBTU)*	AECO/NIT Spot *(Cdn$/MMBTU)*	Pentane Plus Edmonton *(Cdn$/bbl)*	Butane Edmonton *(Cdn$/bbl)*	Propane Edmonton *(Cdn$/bbl)*	Operating Cost Inflation Rate *(%/yr)*	Capital Cost Inflation Rate *(%/yr)*	Exchange Rate *(US$/Cdn$)*
Forecast										
2025	71.58	94.79	3.31	2.36	100.14	51.15	33.56	0.00%	0.00%	0.712
2026	74.48	97.04	3.73	3.33	100.72	49.99	32.78	2.00%	2.00%	0.728
2027	75.81	97.37	3.85	3.48	100.24	50.16	32.81	2.00%	2.00%	0.743
2028	77.66	99.80	3.93	3.69	102.73	51.41	33.63	2.00%	2.00%	0.743
2029	79.22	101.79	4.01	3.76	104.79	52.44	34.30	2.00%	2.00%	0.743
2030	80.80	103.83	4.09	3.83	106.86	53.49	34.99	2.00%	2.00%	0.743
2031	82.42	105.91	4.17	3.91	109.01	54.56	35.69	2.00%	2.00%	0.743
2032	84.06	108.03	4.26	3.99	111.19	55.65	36.40	2.00%	2.00%	0.743
2033	85.74	110.19	4.34	4.07	113.42	56.76	37.13	2.00%	2.00%	0.743
2034	87.46	112.39	4.43	4.15	115.69	57.90	37.87	2.00%	2.00%	0.743
2035	89.21	114.64	4.52	4.23	118.00	59.05	38.63	2.00%	2.00%	0.743
2036+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.00%	2.00%	0.743

Reconciliations of Changes in Reserves[1]

The following tables set forth a reconciliation of the Corporation's working interest reserves by total Proved, total Probable and total Proved plus Probable reserves as at December 31, 2024, against such reserves as at December 31, 2023, based on forecast price and cost assumptions.

	Light and Medium Crude Oil *(Mbbls)*			Heavy Crude Oil *(Mbbls)*			Tight Oil *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2023	46,823	33,119	79,942	21,163	6,677	27,840	238,989	142,434	381,422	189,720	93,735	283,455
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	240	(195)	45	—	—	—	32,259	3,402	35,661	23,589	2,930	26,519
Technical Revisions [3]	2,191	(29)	2,162	13	(11)	2	6,318	(729)	5,589	(711)	(768)	(1,480)
Acquisitions [4]	—	—	—	—	—	—	544	200	744	115	43	157
Dispositions [5]	(25,780)	(24,902)	(50,682)	(20,586)	(6,666)	(27,252)	(11,793)	(6,178)	(17,971)	(8,464)	(6,248)	(14,712)
Economic Factors [6]	152	32	184	—	—	—	6	18	25	(750)	(255)	(1,006)
Production [7]	(3,161)	—	(3,161)	(590)	—	(590)	(25,600)	—	(25,600)	(16,426)	—	(16,426)
December 31, 2024 [1]	20,465	8,025	28,490	—	—	—	240,724	139,147	379,871	187,072	89,436	276,508

	Shale Gas (Natural Gas) *(MMcf)*			Conventional Natural Gas (Natural Gas) *(MMcf)*			Total BOE *(Mboe)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2023	1,588,202	917,729	2,505,931	41,151	24,721	65,872	768,254	433,040	1,201,294
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	293,710	43,290	337,000	134	(74)	60	105,063	13,339	118,402
Technical Revisions [3]	10,419	(15,129)	(4,711)	1,180	(470)	710	9,744	(4,137)	5,607
Acquisitions [4]	3,095	1,158	4,253	—	—	—	1,174	436	1,611
Dispositions [5]	(5,733)	(2,264)	(7,997)	(33,074)	(21,075)	(54,149)	(73,090)	(47,884)	(120,975)
Economic Factors [6]	(8,647)	(2,131)	(10,777)	(227)	43	(183)	(2,071)	(553)	(2,624)
Production [7]	(143,669)	—	(143,669)	(1,462)	—	(1,462)	(69,966)	—	(69,966)
December 31, 2024 [1]	1,737,377	942,653	2,680,030	7,702	3,145	10,848	739,108	394,241	1,133,349

Notes:
(1) Numbers may not add due to rounding.
(2) The Corporation's development strategy is focused on developing its Kaybob Duvernay and Alberta Montney assets, along with low risk infill development in the Viewfield Bakken and Shaunavon resource plays. The Corporation continues its decline mitigation efforts through implementing waterflood and polymer flood development within its Saskatchewan assets. The majority of the extensions in 2024 were in the Montney and Duvernay plays.
(3) The Corporation realized positive technical revisions primarily due to positive performance on producing wells in the Kaybob Duvernay. Overall, total revisions made up a minor portion of the year-over-year changes.
(4) The Corporation closed a minor working interest top-up acquisition within its Montney play.
(5) The Corporation completed dispositions of non-core assets, including Swan Hills, Southern Alberta and portions of Southeast Saskatchewan and Southwest Saskatchewan.
(6) Decreases in reserves are due to slight decreases in long-term forecast commodity prices, determined by prior year end reserves calculated on current year end price forecasts.
(7) The Corporation produced an average of 191,163 boe per day.

Undeveloped Reserves

The following discussion generally describes the basis on which we attribute Proved and Probable undeveloped reserves. Our near-term plans for developing our undeveloped reserves are described in the section "*Major Oil and Gas Properties*".

Proved Undeveloped Reserves

Proved Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. These reserves represent a high degree of certainty to be recoverable, and mostly relate to planned infill drilling and proximal offset locations to current producing entities.

The Corporation has extensive Proved development opportunities that are prioritized based on a disciplined set of criteria including, but not limited to, time for payout, rate of return, maturity of land tenure, reserve booking opportunities, proximity to transportation and marketing, as well as anticipated production rates. With this extensive portfolio of opportunities, it would be unrealistic, both from a cash flow as well as a physical ability, to completely execute on the entire portfolio of booked opportunities within two years, however, approximately 40% of the development spending occurs within this timeframe.

The development of these reserves have been based on current and planned capital activity levels, with no material deferrals of development opportunities beyond these normal budgetary constraints. The majority of these reserves are planned to be developed within a three-year timeframe, which represents approximately 54% of the net undeveloped location count, as well as 63% of the net total future development capital. These development activities are directed mostly to the Corporation's core focus areas of the Montney, Kaybob Duvernay, Viewfield Bakken and Shaunavon resource plays. The current market environment has resulted in long term sustainability. When combined with an extensive location inventory, this results in an extended time period for full development.

The following tables provide the timing of the initial reserve assignments for the Corporation's gross Proved Undeveloped reserves.

Timing of Initial Proved Undeveloped Reserve Assignment

	Light & Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Tight Oil (Mbbl)		Natural Gas Liquids (Mbbl)	
	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End
2022	1,108	10,757	—	1,731	167	48,806	25,624	69,253
2023	21	9,551	—	1,729	74,385	106,423	51,082	107,124
2024	—	2,038	—	—	26,851	112,787	19,162	107,985

	Shale Gas (MMcf)		Conventional Natural Gas (MMcf)		Oil Equivalent (Mboe)	
	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End
2022	117,568	235,901	528	3,491	46,581	170,446
2023	737,162	949,769	—	3,013	248,349	383,624
2024	261,985	1,085,252	—	679	89,678	403,798

Notes:
(1) "First attributed" refers to reserves first attributed at year-end to corresponding fiscal year.

Probable Undeveloped Reserves

Probable Undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, and lands contiguous to production. These reserves represent quantities that are less certain to be recovered than Proved reserves.

In the reserve evaluation, development of the Proved plus Probable reserves is balanced across a five-to-eight year timeframe to closely match the aggregate internal development schedule and represent a practicable development program. A large portion of these reserves are planned to be developed within a three-year timeframe, representing approximately 36% of the net undeveloped location count, as well as 48% of the total net future development costs. The current market environment has resulted in long term sustainability. When combined with extensive location inventory, this results in an extended full development time period.

This broader distribution of development activities continues to focus on the Corporation's core areas, while reclassifying current Probable locations to Proved locations during the early years of development. These development activities are directed mostly to the Corporation's core focus areas of the Montney, Kaybob Duvernay, Viewfield Bakken and Shaunavon resource plays.

The following tables provide the timing of the initial reserve assignments for the Corporation's Probable Undeveloped reserves.

Timing of Initial Probable Undeveloped Reserves Assignment

	Light & Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Tight Oil (Mbbl)		Natural Gas Liquids (Mbbl)	
	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End
2022	470	23,332	—	1,481	57	60,050	6,384	29,544
2023	8	22,131	—	1,481	66,300	100,756	50,021	70,098
2024	—	2,128	—	—	6,515	100,911	4,506	65,895

	Shale Gas (MMcf)		Conventional Natural Gas (MMcf)		Oil Equivalent (Mboe)	
	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End	First Attributed[1]	Total at Year-End
2022	29,397	91,012	236	14,877	11,849	132,055
2023	687,435	752,281	—	14,694	230,901	322,295
2024	59,117	768,650	—	1,094	20,873	297,225

Notes:
(1) "First attributed" refers to reserves first attributed at year end of the corresponding fiscal year.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. Our reserves are evaluated by McDaniel, an independent engineering firm. Different reserve engineers may make different estimates of reserve quantities based on the same data.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions and judgments, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from numerous factors including, but not limited to, additional development activity, evolving production history, continual reassessment of the viability of production under varying economic conditions, changes in forecast prices, and reservoir performance. Such revisions can be substantial and can be either positive or negative.

Future Development Costs

The table below sets out the development costs deducted in the estimation of future net revenue attributable to total Proved reserves and total Proved plus Probable reserves (using forecast prices and costs).

Company Annual Capital Expenditures (MM$) [1]		
Year	**Total Proved**	**Total Proved Plus Probable**
2025	1,357	1,465
2026	1,308	1,375
2027	1,455	1,551
2028	1,314	1,679
2029	1,104	1,675
2030	33	1,023
2031	4	280
2032	4	132
2033	3	3
2034	3	3
2035	—	—
2036	—	—
Subtotal	6,586	9,186
Remainder	—	—
Total	6,586	9,186
10% Discounted	5,288	6,957

Notes:
(1) Due to the nature of the resource style plays that Veren is focused on, with large contiguous blocks of land, a large number of Proved as well as Proved plus Probable locations have been booked. The scheduling of locations in the Veren Reserve Report have a similar drilling timing as the Corporation's long-term development plan, with development drilling scheduled to occur within a five year period for Proved reserves, extending up to eight years for Probable reserves.

We estimate that our internally generated cash flow will be sufficient to fund the future development costs ("**FDC**") disclosed above. In addition, we have access to debt financing through our bank credit facilities and through debt capital markets, if available on terms acceptable to us.

Major Oil and Gas Properties

The following is a description of the major oil and natural gas producing properties in which Veren has an interest and that are material to the Corporation's operations and activities. All of the Corporation's assets are located onshore within Canada. The Corporation holds no interests in any plants, facilities or installations that are significant beyond normal oil and gas operating practices. Unless otherwise noted, reserve amounts are gross, based on escalating cost and price assumptions as evaluated in the Veren Reserve Report as at December 31, 2024.

Alberta Montney Area

The Corporation's Montney production is a combination of tight oil, natural gas, and natural gas liquids, weighted approximately 53% to oil and natural gas liquids. The Corporation continued developing the play using pad based multi-staged fractured horizontal wells. In 2024, Veren's production from the Montney averaged approximately 89,600 boe per day.

In the Montney, the Corporation spent $766 million, including $31 million on land, representing 49% of its 2024 capital program, drilling 61 (60.6 net) horizontal wells.

At year-end 2024, the Corporation's total Proved plus Probable reserves in the Montney were 544.2 MMboe, representing approximately 48% of the Corporation's total Proved plus Probable reserves.

As at December 31, 2024, Veren has allocated approximately 52% of the Corporation's 2025 capital budget to developing the Montney resources play in Alberta.

Kaybob Duvernay Area

The Corporation's Kaybob Duvernay production is approximately 60% natural gas liquids, weighted towards condensate, along with natural gas. The Corporation is developing the play using multi-staged fractured horizontal wells. In 2024, Veren's production averaged approximately 49,500 boe per day.

In the Kaybob Duvernay, the Corporation spent $582 million, including $1.6 million on land, representing 38% of its 2024 capital program, drilling 39 (39.0 net) wells.

At year-end 2024, the Corporation's total Proved plus Probable reserves in Kaybob Duvernay were 340.8 MMboe, representing approximately 30% of the Corporation's total Proved plus Probable reserves.

As of December 31, 2024, Veren has allocated approximately 37% of the Corporation's 2025 capital budget to developing the Kaybob Duvernay resource play in Alberta.

Viewfield Area

In the Viewfield resource area, located in southeastern Saskatchewan, the Corporation has development in the Bakken resource play, as well as conventional plays, including the Frobisher and Midale. In 2024, Veren's production averaged approximately 27,700 boe per day in the area. The majority of the production is from the Bakken resource, which is a high-quality light oil and exploited using a combination of multi-stage fractured horizontal wells and open hole multi-lateral wells. The core area of the Bakken resource has mostly been unitized, which has allowed Veren to implement various waterflood projects.

Veren spent $118 million, including $9 million on land, representing approximately 8% of its 2024 capital development program, drilling 53 (43.6 net) wells. The Corporation also continued to focus on waterflood development expansion.

At year-end 2024, the Corporation's total Proved plus Probable reserves in the Viewfield area were 161.6 MMboe, representing approximately 14% of the Corporation's total Proved plus Probable reserves.

As of December 31, 2024, Veren has allocated approximately 5% of the Corporation's 2025 capital budget to development of the Viewfield area, focused on the Bakken resource play and conventional Frobisher and Midale drilling, as well as additional waterflood development.

Shaunavon Area

In the Shaunavon resource area, located in southwest Saskatchewan, the Corporation has development occurring in the Upper and Lower Shaunavon resource zones, as well as conventional Upper Shaunavon pools, all of which are medium quality oil. The Corporation has developed tight oil Upper and Lower resource plays using multi-stage fracture stimulated horizontal wells. In 2024, Veren's production averaged approximately 17,500 boe per day.

Veren spent $86 million, including $0.2 million on land, representing approximately 6% of its 2024 capital development program, drilling 25 (22.5 net) wells. The Corporation has also continued to focus on waterflood expansion and has continued its enhanced oil recovery project in a conventional Upper Shaunavon pool.

As of year-end 2024, the Corporation's total Proved plus Probable reserves in the Shaunavon area were 86.5 MMboe, representing approximately 8% of the Corporation's total Proved plus Probable reserves.

As of December 31, 2024, Veren has allocated approximately 4% of the Corporation's 2025 capital budget to development of the Shaunavon area, focused on both Upper and Lower Shaunavon drilling, as well as continued expansion of waterflood and polymer enhanced oil recovery projects.

Oil and Gas Wells

Producing Wells

	Oil		Gas	
Region	*Gross*	*Net*	*Gross*	*Net*
Saskatchewan	3,969	3,714	—	—
Alberta	402	388	447	400
Total [3]	4,371	4,103	447	400

Non-Producing Wells [2]

	Oil		Gas	
Region	*Gross*	*Net*	*Gross*	*Net*
Saskatchewan	2,265	2,027	8	4
Alberta	113	80	288	205
Total [3]	2,378	2,108	296	209

Notes:
(1) Gross and net producing and non-producing oil and gas counts include both reserve assigned and non-reserve assigned wells.
(2) Active injection wells are reflected in the non-producing well count. Saskatchewan includes 963 (946 net) injection wells and Alberta includes 4 (3 net).
(3) Numbers may not add due to rounding.

All of the Corporation's oil and gas wells are onshore. The Corporation's non-producing wells are generally situated within defined developed areas and include recent drills awaiting final preparation prior to being placed on production; existing wells that may be waiting on improved economic conditions to restart; wells currently in use for observation or monitoring; wells awaiting recompletion in secondary zones or as injectors; or wells scheduled for abandonment. These non-producing entities include wells with reserve assignments as well as currently non-booked wells, which will have various terms of being non-producing from recent to longer-term.

Developed non-producing reserves represent only 0.3% of the Corporation's total Proved reserve category, and 0.3% of the total Proved plus Probable reserve category. The Corporation's wells in the developed non-producing category exist across most of the Corporation's areas and mostly represent wells awaiting final preparation for production, plus those awaiting well reactivation.

Properties With No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which we have an interest and also the number of net acres for which our rights to develop or exploit will, absent further action, expire within one year.

	December 31, 2024		
Region	Gross Acres	Net Acres	Net Acres Expiring Within One Year
Alberta	607,922	536,278	32,953
Saskatchewan	456,999	439,162	26,159
Manitoba	2,475	2,475	—
Total	1,067,396	977,915	59,112

The Corporation has no material drilling commitments relating to unproved properties.

Drilling Activity

The following table summarizes the gross and net exploration and development wells we participated in during the year ended December 31, 2024.

	Development Wells		**Exploration Wells** [2]		**Total Wells**	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	136	122	1	1	137	123
Natural Gas wells [3]	34	34	—	—	34	34
Service wells	9	9	—	—	9	9
Stratigraphic test	—	—	—	—	—	—
Dry holes	—	—	—	—	—	—
Total [1]	179	165	1	1	180	166

Notes:
(1) Numbers may not add due to rounding.
(2) Exploration wells in this grouping are based on the well license classification at the time of drilling.
(3) Kaybob Duvernay wells where the primary product is condensate.

For details on important exploration and development activities during 2024, see *"Statement of Reserves Data and Other Oil and Gas Information – Major Oil and Gas Properties"*.

The Corporation has no work commitments for its proved properties (including drilling commitments) in Canada or the U.S. for the next three years.

Tax Horizon

Veren had tax pools of approximately $6.8 billion at December 31, 2024, which are deductible against future taxable income. Based on this tax pool balance and forecast cash flows using January 1, 2025 forecast prices from the average of three Independent Reserve Evaluators (McDaniel, GLJ Ltd. and Sproule Associates Ltd.), with the Corporation's development capital plans, Veren does not expect to be taxable until 2026. Veren is subject to other taxes, such as payroll taxes, property taxes, carbon taxes, sales taxes and foreign withholding taxes as part of its ongoing business.

Costs Incurred[1]

The following table summarizes our property acquisition costs, exploration costs and development costs for the year ended December 31, 2024.

($ millions) Acquisition Costs			
Proved Properties [2]	Unproved Properties	Exploration Costs	Development Costs
16.6	15.8	14.5	1,535.4

Notes:
(1) Costs incurred exclude capitalized administration.
(2) Excludes disposition proceeds of $1.04 billion for proved properties.

Production Estimates

The following table discloses the gross volume of production for each product type estimated by McDaniel for 2025 in the estimates of future net revenue with forecast pricing from Proved reserves disclosed above under the heading "*Reserves Data – Forecast Prices and Costs*".

Region	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas	Total
	(bbls/d)	*(bbls/d)*	*(bbls/d)*	*(bbls/d)*	*(Mcf/d)*	*(Mcf/d)*	*(boe/d)*
Alberta	184	—	37,149	44,854	392,044	1,762	147,822
Southwest Saskatchewan	2,158	—	10,794	319	8,875	418	14,819
Southeast Saskatchewan	3,747	—	15,052	4,311	8,000	796	24,577
Total Corporate[1]	6,089	—	62,995	49,484	408,919	2,977	187,217

Notes:
(1) Numbers may not add due to rounding.

In 2025, production in the Montney in Alberta is estimated at 88,039 boe per day (comprised of 37,149 bbl/d Tight Oil; 150 bbl/d Light & Medium Oil; 9,134 bbl/d NGLs; 248,663 Mcf/d Shale Gas; and 967 Mcf/d Conventional Natural Gas). Production in the Kaybob Duvernay area of Alberta is estimated at 59,692 boe per day (comprised of 35,715 bbl/d NGLs; 143,381 Mcf/d Shale Gas; and 477 Mcf/d Conventional Natural Gas). Condensate is estimated to make up 44% of 2025 total production from Kaybob Duverney. The Montney and Kaybob Duvernay areas make up 47% and 32% of the Corporation's Proved production estimate in the Veren Reserve Report, respectively. Remaining areas each account for a smaller portion of the Corporation's production estimates for 2025.

The following table discloses, for each product type, the gross volume of production estimated by McDaniel for 2025 in the estimates of future net revenue with forecast pricing from Proved plus Probable reserves disclosed above under the heading "*Reserves Data – Forecast Prices and Costs*".

Region	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas	Total
	(bbls/d)	*(bbls/d)*	*(bbls/d)*	*(bbls/d)*	*(Mcf/d)*	*(Mcf/d)*	*(boe/d)*
Alberta	208	—	40,237	47,019	413,964	1,839	156,764
Southwest Saskatchewan	2,301	—	11,554	339	9,473	446	15,847
Southeast Saskatchewan	4,007	—	15,878	4,476	8,266	866	25,882
Total Corporate[1]	6,516	—	67,668	51,834	431,702	3,150	198,493

Notes:
(1) Numbers may not add due to rounding.

In 2025, production in the Montney in Alberta is estimated at 94,613 boe per day (comprised of 40,237 bbl/d Tight Oil; 173 bbl/d Light & Medium Oil; 9,756 bbl/d NGLs; 265,659 Mcf/d Shale Gas; and 1,026 Mcf/d Conventional Natural Gas). Production in the Kaybob Duvernay area of Alberta is estimated at 62,058 boe per day (comprised of 37,259 bbl/d NGLs; 148,305 Mcf/d Shale Gas; and 488 Mcf/d Conventional Natural Gas). Condensate is estimated to make up 44% of 2025 total production from Kaybob Duvernay. The Montney and Kaybob Duvernay areas make up 48% and 31% of the Corporation's Proved plus Probable production estimate in the Veren Reserve Report, respectively. Remaining areas each account for a smaller portion of the Corporation's production estimates for 2025.

Production History

The following tables disclose, on a quarterly and annual basis for the year ended December 31, 2024, our share of average daily production volume (prior to deducting royalties), and the prices received, royalties, production costs and transportation costs incurred, and netbacks received on a per unit of volume basis for each product type.

Average Daily Production Volume[1]

	Three Months Ended				Year Ended
	March 31, 2024	June 30, 2024	Sept. 30, 2024	Dec. 31, 2024	2024
Light and Medium Crude Oil (bbls/d)	11,434	9,653	7,062	6,439	8,637
Heavy Crude Oil (bbls/d)	3,620	2,866	—	—	1,612
Tight Oil (bbls/d)	72,849	72,546	67,262	67,177	69,944
NGLs (bbls/d) [2]	44,780	42,375	44,908	47,434	44,881
Shale Gas (Mcf/d)	388,432	387,893	390,322	403,412	392,539
Conventional Natural Gas (Mcf/d)	6,773	3,357	3,260	2,615	3,995
Total (boe/d)	198,551	192,648	184,829	188,721	191,163

Notes:
(1) Numbers may not add due to rounding.
(2) For the year ended December 31, 2024, the Corporation's average condensate production was 27,349 bbl/s, which is included in NGLs production.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Light and Medium Crude Oil

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2024	June 30, 2024	Sept. 30, 2024	Dec. 31, 2024	2024
Prices Received	80.68	91.45	94.99	85.97	87.60
Royalties	(13.85)	(14.25)	(18.39)	(14.29)	(14.97)
Production Costs[1]	(20.96)	(21.46)	(24.38)	(20.59)	(21.73)
Transportation Costs[1]	(1.17)	(0.49)	(0.49)	(0.47)	(0.71)
Netback Received	44.70	55.25	51.73	50.62	50.19

Notes:
(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on several assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Heavy Crude Oil

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2024	June 30, 2024	Sept. 30, 2024	Dec. 31, 2024	2024
Prices Received	74.47	86.31	—	—	79.70
Royalties	(17.46)	(20.89)	—	—	(18.73)
Production Costs[1]	(19.41)	(19.69)	—	—	(19.53)
Transportation Costs[1]	(2.67)	(2.65)	—	—	(2.50)
Netback Received	34.93	43.08	—	—	38.94

Notes:
(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on several assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Tight Oil

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2024	June 30, 2024	Sept. 30, 2024	Dec. 31, 2024	2024
Prices Received	91.76	100.47	95.92	94.96	95.79
Royalties	(10.00)	(10.14)	(11.94)	(10.59)	(10.65)
Production Costs[(1)]	(23.84)	(23.58)	(24.62)	(22.74)	(23.70)
Transportation Costs[(1)]	(5.61)	(6.18)	(5.68)	(4.94)	(5.61)
Netback Received	52.31	60.57	53.68	56.69	55.83

Notes:
(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on several assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – NGLs

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2024	June 30, 2024	Sept. 30, 2024	Dec. 31, 2024	2024
Prices Received	69.46	75.40	71.71	74.58	72.78
Royalties	(7.22)	(9.59)	(8.15)	(8.71)	(8.40)
Production Costs[(1)]	(10.90)	(12.74)	(12.54)	(11.97)	(12.03)
Transportation Costs[(1)]	(3.56)	(4.16)	(4.18)	(3.43)	(3.82)
Netback Received	47.78	48.91	46.84	50.47	48.53

Notes:
(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on several assumptions.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Shale Gas

	Three Months Ended				Year Ended
($ per Mcf)	March 31, 2024	June 30, 2024	Sept. 30, 2024	Dec. 31, 2024	2024
Prices Received	3.13	2.14	2.07	2.90	2.56
Royalties[(2)]	0.04	0.17	0.26	0.20	0.17
Production Costs[(1)]	(0.57)	(0.30)	(0.25)	(0.45)	(0.39)
Transportation Costs[(1)]	(0.79)	(0.61)	(0.64)	(0.77)	(0.70)
Netback Received	1.81	1.40	1.44	1.88	1.64

Notes:
(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on several assumptions.
(2) Royalties include the impact of the gas cost allowance.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Conventional Natural Gas

	Three Months Ended				Year Ended
($ per Mcf)	March 31, 2024	June 30, 2024	Sept. 30, 2024	Dec. 31, 2024	2024
Prices Received	2.81	2.43	1.64	1.62	2.30
Royalties[(2)]	1.21	0.14	5.76	2.75	2.17
Production Costs[(1)]	(0.51)	(0.34)	(0.20)	(0.25)	(0.37)
Transportation Costs[(1)]	(0.37)	(0.35)	(0.22)	(0.16)	(0.30)
Netback Received	3.14	1.88	6.98	3.96	3.80

Notes:
(1) Production costs and transportation costs consist of direct costs incurred to operate both oil and gas wells. Costs are allocated between all product types based on several assumptions.
(2) Royalties include the impact of the gas cost allowance.

Production Volume by Field

The following table discloses for each important field, and in total, our production volumes for the year ended December 31, 2024, for each product type.

Region	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	NGLs	Shale Gas	Conventional Natural Gas	Total
	(bbls/d)	*(bbls/d)*	*(bbls/d)*	*(bbls/d)*	*(Mcf/d)*	*(Mcf/d)*	*(boe/d)*
Montney	—	—	37,454	8,969	259,278	28	89,641
Kaybob Duvernay	16	—	124	30,081	114,589	819	49,456
Viewfield	4,508	—	17,010	4,616	8,307	1,159	27,711
Shaunavon	2,009	—	13,516	365	9,569	333	17,541
Other [2]	2,104	1,612	1,840	850	796	1,656	6,814
Total [1]	8,637	1,612	69,944	44,881	392,539	3,995	191,163

Notes:
(1) Numbers may not add due to rounding.
(2) Relates to remaining assets in Canada, which includes properties sold in 2024.

ADDITIONAL INFORMATION RESPECTING VEREN

Directors and Officers

Veren has a Board of Directors currently consisting of eleven individuals. The directors are elected by Shareholders and hold office until the next annual meeting of Shareholders of the Corporation.

The name, municipality of residence and principal occupation during the last five years of each of the directors and executive officers of the Corporation are as follows:

Name and Municipality of Residence	Position Held with the Corporation	Date First Elected or Appointed as Director
Craig Bryksa [4] Calgary, Alberta	President, Chief Executive Officer and Director	2018
Kenneth R. Lamont Calgary, Alberta	Chief Financial Officer	Not applicable
Ryan Gritzfeldt Calgary, Alberta	Chief Operating Officer	Not applicable
Mark G. Eade Calgary, Alberta	Senior Vice President, General Counsel and Corporate Secretary	Not applicable
Garret Holt Calgary, Alberta	Senior Vice President, Strategy and Planning	Not applicable
Michael Politeski Calgary, Alberta	Senior Vice President, Finance and Treasurer	Not applicable
Shelly Witwer Calgary, Alberta	Senior Vice President, Business Development	Not applicable
Justin Foraie Calgary, Alberta	Senior Vice President, Operations and Marketing	Not applicable
Barbara Munroe [6] Calgary, Alberta	Director and Chair of the Board	2016
Corey Bieber [1] [5] Calgary, Alberta	Director	2025
James E. Craddock [2] [3] [5] Whitney, Texas	Director	2019
John P. Dielwart [3] [4] Calgary, Alberta	Director	2019
Mike Jackson [1] [5] Calgary, Alberta	Director	2016
Jodi J. Jenson Labrie [1] [2] Calgary, Alberta	Director	2025
Jennifer F. Koury [2] [5] Calgary, Alberta	Director	2019
François Langlois [1] [3] [4] Calgary, Alberta	Director	2018
Myron M. Stadnyk [1] [2] [4] Calgary, Alberta	Director	2020
Mindy Wight [2] Prince George, British Columbia	Director	2022

Notes:
(1) Member of the Audit Committee.
(2) Member of the Human Resources and Compensation Committee.
(3) Member of the Reserves Committee.
(4) Member of the Environmental, Safety and Sustainability Committee.
(5) Member of Corporate Governance and Nominating Committee.
(6) Chair of the Board serves in an *ex officio* capacity on each Committee.

As at February 12, 2025, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 4,184,381 Common Shares, representing approximately 0.7% of the issued and outstanding Common Shares. Including restricted shares and options, ownership increased to 0.8% on a fully diluted basis.

Craig Bryksa, President, Chief Executive Officer and Director

Craig Bryksa is the President, Chief Executive Officer and a Director of Veren, roles he has held since September 2018. Prior to his current position, Mr. Bryksa was Vice President, Engineering West and has held many senior management roles with Veren since joining the Corporation in 2006, directly overseeing the development and operations of each of Veren's core assets.

Mr. Bryksa is the past Chair of the Board of Governors at the Canadian Association of Petroleum Producers ("**CAPP**"). He has significant experience as a professional engineer in the oil and gas industry, working with companies such as Enerplus Resources Fund and McDaniel & Associates Consultants. Mr. Bryksa is a member of the Association of Professional Engineers and Geoscientists of Alberta ("**APEGA**") and Association of Professional Engineers and Geoscientists of Saskatchewan ("**APEGS**"). He holds a Bachelor of Applied Science degree in petroleum engineering from the University of Regina.

Ken Lamont, Chief Financial Officer

Ken Lamont is the Chief Financial Officer of Veren, a role he has held since January 2016. Prior to that, he was Vice President, Finance and Treasurer for Veren. Mr. Lamont has worked in the oil and gas industry since 2001, having held a variety of roles with companies such as Shelter Bay Energy Inc., Direct Energy Marketing Ltd. and Shell Trading Gas and Power Canada Ltd. Prior to 2001, he was a Senior Manager at PricewaterhouseCoopers LLP.

Mr. Lamont holds a Bachelor of Commerce degree (with distinction) from the University of Alberta, is a Chartered Professional Accountant and holds the ICD.D designation. He is a member of the Chartered Professional Accountants of Alberta and a member of the Institute of Corporate Directors.

Ryan Gritzfeldt, Chief Operating Officer

Ryan Gritzfeldt is the Chief Operating Officer of Veren, a role he has held since 2018. Prior to that, he was Vice President, Marketing and Innovation and Vice President, Engineering and Business Development East for Veren from 2010 until 2018. Mr. Gritzfeldt has worked in the oil and gas industry since 1998, having held a variety of roles with companies such as Shelter Bay Energy Inc. and Talisman Energy Inc. in addition to Veren.

Mr. Gritzfeldt is a member of APEGA and APEGS. He holds a Bachelor of Applied Science degree (with great distinction) in industrial systems engineering from the University of Regina.

Mark Eade, Senior Vice President, General Counsel and Corporate Secretary

Mark Eade is the Senior Vice President, General Counsel and Corporate Secretary at Veren. Mr. Eade has served as Corporate Secretary since 2004 and was formerly Vice President, General Counsel and Corporate Secretary. Prior to being named Vice President at Veren in September 2015, he was a partner with Norton Rose Fulbright Canada LLP from August 2011 to August 2015. Prior thereto, Mr. Eade was a partner at McCarthy Tétrault LLP. Mr. Eade has over 30 years of experience in corporate governance, securities and mergers and acquisitions law and has represented clients in many significant acquisitions and public offerings.

Mr. Eade holds a Bachelor of Commerce degree (with honors) and a LL.B. degree from the University of Saskatchewan and was called to the Alberta bar in 1994. He is a member of the Law Society of Alberta and the Canadian Bar Association.

Garret Holt, Senior Vice President, Strategy and Planning

Garret Holt is Veren's Senior Vice President, Strategy and Planning, and has been on the Corporation's executive team since 2019. Mr. Holt has over 30 years of experience in the oil and gas industry. Most recently, he was an Executive Director in Energy Investment Banking with JPMorgan. Prior to that, Mr. Holt held senior executive positions with Wapiti Energy, LLC as Chief Operating Officer and Fairways E&P, LLC as Senior Vice President of Exploration and Production.

He graduated from the University of Tulsa with a Bachelor of Science, Petroleum Engineering (Magna Cum Laude) and is a Registered Professional Engineer.

Michael Politeski, Senior Vice President, Finance and Treasurer

Michael Politeski is the Senior Vice President, Finance and Treasurer. He has held an executive role since joining the Corporation in 2015. Mr. Politeski has worked in the energy industry since 2003 in various financial and managerial positions. Prior to joining Veren, Mr. Politeski was the Treasurer and Corporate Controller of Enerplus Corporation and also held management roles with Halliburton Canada and KPMG LLP.

Mr. Politeski is a Chartered Professional Accountant and holds a Bachelor of Commerce degree (with distinction) from the University of Saskatchewan. He is a member of the Institute of Chartered Professional Accountants of Alberta.

Shelly Witwer, Senior Vice President, Business Development

Shelly Witwer is Veren's Senior Vice President, Business Development. Since joining the Corporation in 2007, she has held a number of senior management roles, including Vice President, Land and Vice President, Business Development. Ms. Witwer has significant experience in land and business development roles, having worked for companies such as BP Energy, Burlington Resources and Bear Ridge Resources.

Ms. Witwer is a member of the Canadian Association of Land and Energy Professionals and the Petroleum and Acquisition Divestment Association. She holds a Bachelor of Commerce degree and a Bachelor of Arts degree in Energy Economics from the University of Calgary.

Justin Foraie, Senior Vice President, Operations and Marketing

Justin Foraie is the Senior Vice President, Operations and Marketing for Veren. Mr. Foraie has been with the Corporation since 2009 and has held roles of increasing responsibility within engineering, operations and marketing, in both Canada and the United States, and has served in an executive role since 2018. Prior to joining Veren, Mr. Foraie worked for Talisman Energy Inc.

Mr. Foraie graduated from the University of Regina with a Bachelor of Applied Science degree in Petroleum Systems Engineering and the Stanford Graduate School of Business LEAD program. Mr. Foraie became a Registered Professional Engineer in 2008 and is a member of APEGA and APEGS.

Barbara Munroe, Chair of the Board

Ms. Barbara Munroe was admitted to the Law Society of Alberta in 1991 and brings over 30 years of legal experience and industry diversification to the Board. Prior to retiring in March 2019, Ms. Munroe served as Executive Vice President, Corporate Services and General Counsel for WestJet Airlines, a position she held since November 2016. Ms. Munroe joined WestJet in November 2011 as Vice President & General Counsel and was promoted to Senior Vice President, Corporate Services & General Counsel in June 2015. She was the Assistant General Counsel, Upstream at Imperial Oil Ltd. from 2008 to 2011 and the Senior Vice President, Legal/IP & General Counsel, Corporate Secretary for SMART Technologies Inc. from 2000 to 2008. Prior to that, Ms. Munroe practiced at a national law firm. Ms. Munroe additionally serves as a Director of ENMAX Corporation, and a former trustee and vice-chair of the Alberta Cancer Foundation.

Ms. Munroe holds the ICD.D designation and is a member of the Institute of Corporate Directors. She holds a Bachelor of Commerce, Finance degree and a Bachelor of Law degree, both from the University of Calgary. As Chair of the Board, Ms. Munroe serves on each committee in an *ex officio* capacity.

Corey Bieber, Director

Mr. Corey Bieber has over 35 years of financial and management experience within the energy industry. Most recently, Mr. Bieber served as an external Finance Committee member at TransMountain Corporation from 2023-2024. Prior thereto, he held progressively senior roles at Canadian Natural Resources Ltd. ("CNRL"), culminating in him serving as Chief Financial Officer from 2012-2018 and as an Executive Advisor from 2018-2022. Mr. Bieber also served as a board member on several CNRL subsidiaries and acted as Audit Committee chair for certain equity accounted investees. Prior to joining CNRL, he was Director of Financial Reporting at Enbridge Inc.

Mr. Bieber holds a Bachelor of Commerce degree from the University of Calgary and has a Chartered Professional Accountant designation. His community efforts include active support of numerous charity activities such as the United Way, and prior involvement as a member of the Heart & Stroke Alberta Board.

James E. Craddock, Director

Mr. James E. Craddock is a seasoned upstream executive who possesses broad-based technical knowledge with over 30 years of experience. He served on Noble Energy Inc.'s Board of Directors since its merger with Rosetta Resources Inc. from 2015 to 2020 and served as the Chairman, Chief Executive Officer and President of Rosetta from 2013 to 2015. Previously, he was the Executive Director and Chief Operating Officer for BPI Industries Inc. and held several positions of increasing responsibility over a 20-year career at Burlington Resources Inc. Mr. Craddock additionally serves as director of Amplify Energy Corp.

Mr. Craddock holds a Bachelor of Science in Mechanical Engineering from Texas A&M University.

John P. Dielwart, Director

Mr. John P. Dielwart brings a wealth of experience and knowledge to Veren's Board, developed through his varied 40 plus year career in the oil and gas sector. Most notably, Mr. Dielwart is a founding member of ARC Resources Ltd., holding the position of Chief Executive Officer from 2001 to 2013. He is also a Partner in ARC Financial Corp., sitting on its investment committee where he provides leadership support on various complex issues, including internal governance and investment decision-making. Prior to joining ARC in 1996, Mr. Dielwart spent 12 years with a major Calgary based oil and natural gas engineering consulting firm, as Senior Vice-President and a Director, where he gained extensive technical knowledge of oil and natural gas properties in Western Canada.

Mr. Dielwart has a Bachelor of Science in Civil Engineering with Distinction from the University of Calgary. He is a professional engineer, holds the ICD.D designation granted by the Institute of Corporate Directors and has served two three-year terms as a Governor of CAPP, including 18 months as Chair. Mr. Dielwart is also Chair of the Board of Directors of TransAlta Corporation.

Mike Jackson, Director

Mr. Mike Jackson worked in the banking industry from 1984 to 2016 and brings more than 30 years of financial experience in corporate and investment banking. Most recently, he was Managing Director - Investment Banking, Scotiabank Global Banking and Markets, with a focus on the oil and gas industry from 2008 until his retirement in 2016. Prior to that, Mr. Jackson held several senior management roles at Scotiabank, including Managing Director, Oil & Gas Industry Head & Calgary Office Head from 1999 to 2007 and Vice President & Office Head, Corporate Banking Calgary from 1997 to 1999.

Mr. Jackson holds a Bachelor of Science degree and a Master of Business Administration, both from Dalhousie University. Mr. Jackson has considerable knowledge of cybersecurity and the evolving area of artificial intelligence. Additionally, Mr. Jackson completed the Executive Management Program at Queen's University and holds the ICD.D designation granted by the Institute of Corporate Directors.

Jodi J. Jenson Labrie, Director

Ms. Jodi J. Jenson Labrie is a highly accomplished financial executive with over 25 years of energy and professional services experience. Ms. Jenson Labrie most recently served as the Senior Vice President and Chief Financial Officer of Enerplus Corporation, an independent North American exploration and production company, from 2015 until the company's combination with Chord Energy in 2024. Prior thereto, she progressed through various leadership roles at Enerplus, including serving as Vice President of Finance from 2013-2015. Prior to joining Enerplus, Ms. Jenson Labrie was a Senior Manager at KPMG LLP specializing in Assurance and Financial Advisory Services.

Ms. Jenson Labrie holds a Bachelor of Commerce from the University of Calgary (Distinction) and both a Chartered Professional Accountant and a Chartered Business Valuator designation. She is a member of the University of Calgary Board of Governors, where she chairs the Budget Committee and serves on the Finance & Property and Audit Committees. Ms. Jenson Labrie also served on the Board of the Explorers and Producers Association of Canada from 2015 to 2020.

Jennifer F. Koury, Director

Ms. Jennifer F. Koury has over 35 years of professional experience, holding various senior executive positions with BHP Biliton from 2011 to 2017. Part of her responsibilities included the development of BHP Billiton's total rewards program for executives and employees of the Petroleum World-Wide Business. Prior to that, she was Vice President of Corporate Services for Enerplus Corp. from 2006 to 2011 and also held senior management positions with Imperial Oil/Exxon Mobil.

Ms. Koury holds a Bachelor of Commerce degree from the University of Alberta and the ICD.D designation granted by the Institute of Corporate Directors. She serves as the Chair of the Board of Directors for the Calgary Zoo, director and Human Resources and Governance Committee Chair for Bird Construction Inc. and director and co-founder for Board Ready Women.

François Langlois, Director

Mr. Langlois is an oil and gas executive who brings over 35 years of domestic and international experience to the Veren Board, most recently from his role as Senior Vice President, Exploration & Production with Suncor Energy Inc., where he was responsible for the financial and operating performance of the group from 2011 until his retirement in 2016. Prior thereto, he was Vice President, Unconventional Gas from 2009 to 2010 and held various roles with Petro-Canada from 1982 to 2009, including as Vice President, Western Canada Production & North American Exploration.

Mr. Langlois holds a Bachelor of Geological Engineering from Laval University (Quebec City) and the ICD.D designation granted by the Institute of Corporate Directors.

Myron M. Stadnyk, Director

Mr. Myron M. Stadnyk has over 40 years of oil and gas experience and is the former President and CEO of ARC Resources Ltd. His extensive career also includes working for a major oil and gas company in both domestic and international operations.

Mr. Stadnyk earned a Bachelor of Science in Mechanical Engineering from the University of Saskatchewan and is a graduate of the Harvard Business School Advanced Management Program. He holds an ICD.D designation and is a member of APEGA.

Mr. Stadnyk previously served on the Board of Directors for both PrairieSky Royalty Ltd. and ARC Resources. Additionally, he dedicated over a decade as a Governor for CAPP. Currently, Mr. Stadnyk is the Chair of the Board for Vermilion Energy Inc. and serves on the Board of Trustees for the University of Saskatchewan Engineering Advancement Trust.

Mindy Wight, Director

Ms. Mindy Wight brings over 15 years of tax and financial expertise from her current role of Chief Executive Officer for the Nch'kay Development Corporation. She previously held the role of Chief Financial Officer, as well as holding the role as Treasurer of the Board of Directors.

Prior to joining Nch'kay Development Corporation in November 2021, Ms. Wight held progressive tax roles at MNP LLP from 2016 to 2021 and most recently was a partner and National Leader of Indigenous Tax Services for the firm. Ms. Wight has also worked for two of the Big Four National accounting firms, the Chartered Accounting School of Business and the Canada Revenue Agency since graduating from the University of Northern British Columbia with a Bachelor of Commerce Degree, Accounting in 2007. Ms. Wight also possesses Chartered Professional Accountant, Chartered Accountant, and Certified Aboriginal Financial Manager designations.

Ms. Wight is a director on the Board of Cedar Leaf Capital Inc. and the Greater Vancouver Board of Trade. Ms. Wight previously held board positions as the Chair of the Board of Directors and Chair of the Finance and Audit Committee for the Nch'kay Development Corporation and was an advisory committee member of the Budget and Financial Committee to the Squamish Nation.

Bankruptcies and Cease Trade Orders

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Corporation is, as of the date of this AIF, or has been, within the last 10 years, been a director or executive officer of any company (including the Corporation) that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the Corporation access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been 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 that person, except for Mr. Dielwart, who was a director of Denbury Resources Inc. when it entered into Chapter 11 proceedings in the United States on July 30, 2020. Denbury Resources Inc. subsequently emerged from Chapter 11 proceedings on September 18, 2020 and Mr. Dielwart resigned as a director of Denbury Resources Inc. at that time.

Penalties or Sanctions

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Corporation, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the 10 years preceding the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual.

Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares.

Common Shares

Each Common Share entitles its holder to receive notice of and to attend all meetings of the Shareholders of the Corporation and to one vote at such meetings. The holders of Common Shares are, at the discretion of the Board of Directors and subject to applicable legal restrictions, entitled to receive any dividends declared by the Board of Directors. The holders of Common Shares are entitled to share equally in any distribution of the assets of the Corporation upon the liquidation, dissolution, bankruptcy or winding up of the Corporation or other distribution of its assets among its Shareholders for the purpose of winding up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to any other shares having priority over the Common Shares.

Premium Dividend™ and Dividend Reinvestment Plan

The DRIP was in effect from 2010 until August 2015, when it was suspended.

Under the Corporation's DRIP, eligible Shareholders may, at their option, reinvest their cash dividends to purchase additional Common Shares at 95% of the average market price (as defined in the DRIP) of a Common Share on the applicable distribution date. The DRIP also provides an alternative where eligible Shareholders may elect, under the premium dividend component, to receive a premium cash distribution equal to 102% of the reinvested cash dividends that such Shareholders would have otherwise been entitled to receive on the applicable dividend date. Generally, no commissions, service charges or brokerage fees will be payable by Shareholders who participate in the DRIP. We have reserved the right to determine how much new equity is available under the DRIP on any particular distribution date. Accordingly, participation in the DRIP may be pro-rated in certain circumstances.

Registered and beneficial owners of Common Shares who are not resident in Canada are not eligible to participate in the DRIP.

Share Dividend Plan

The SDP was in effect from May 9, 2014 until it was suspended on August 12, 2015.

Under the terms of the SDP, eligible Shareholders may, at their option, elect to receive dividends declared on Common Shares as share dividends rather than cash dividends, where such share dividends are declared by the Board of Directors, to be payable in either cash or Common Shares at the election of the Shareholder. Share dividends are satisfied through the issuance of new Common Shares equal to the amount obtained by dividing the dollar amount of the dividend per Common Share by 95% of the average market price (as defined in the SDP) on the TSX. Generally, no commissions, service charges or brokerage fees will be payable by Shareholders who participate in the SDP. Under the SDP, we have reserved the right to determine how much new equity is available under the SDP on any particular distribution date. Accordingly, participation in the SDP may be pro-rated in certain circumstances.

Unlike the dividend reinvestment component of the DRIP, which gives only Shareholders resident in Canada the option to reinvest cash dividends into Common Shares at a 5% discount to market prices, the SDP provides all Shareholders with the option to receive dividends in the form of Common Shares at a 5% discount to current market prices.

Restricted Share Bonus Plan

Under the terms of the Corporation's Restricted Share Bonus Plan, any director, officer or employee of the Corporation who, in each case, in the opinion of the Board of Directors, hold an appropriate position with the Corporation to warrant participation in the Restricted Share Bonus Plan (collectively, the "**RSBP Participants**") may be granted restricted shares ('**Restricted Shares**") which vest over time and, upon vesting, can be redeemed by the holder for cash or Common Shares at the option of the Corporation. The Restricted Share Bonus Plan is administered by the Board of Directors. Under the Restricted Share Bonus Plan at December 31, 2024 the Corporation is authorized to issue up to 9,041,281 Common Shares, of which the Corporation had 1,119,165 Restricted Shares outstanding at December 31, 2024.

The Restricted Shares vest on terms up to three years from the grant date as determined by the Board of Directors. Upon redemption, the Corporation will be required to pay to the RSBP Participant the fair market value of the redeemed Restricted Shares, based on the weighted average of the prices at which the Common Shares traded on the TSX for the five trading days immediately preceding the redemption date, plus any accrued but unpaid dividend amounts in respect of such Restricted Shares (the "**Payout Amount**"). The Payout Amount may be satisfied by the Corporation making a cash payment, the Corporation purchasing Common Shares in the market and delivering such Common Shares to the RSBP Participant or by issuing Common Shares from treasury.

DSU Plan

In 2012, the Corporation established a deferred share unit plan (the "**DSU Plan**") to enhance its ability to attract and retain key personnel (namely, selected officers and employees and non-employee directors) and reward significant performance achievements. Under the terms of the DSU Plan, Designated Employees and Directors (as defined in the DSU Plan), who, in the opinion of the Board of Directors, warrant participation in the DSU Plan (the "**Participants**"), may be granted deferred share units ("**DSUs**"). As at the date hereof, only non-employee directors have been granted DSUs.

Participants that are directors must elect to receive DSUs in lieu of a cash retainer prior to the year in which the retainer will be earned, unless they are elected or appointed part way through a year, in which case they must elect within 30 days of being elected or appointed to receive DSUs for that year. Participants that are Designated Employees must elect to receive DSUs in lieu of all or a portion of their annual bonus entitlement or profit share for the year within 30 days after such Designated Employee has been notified by the Corporation of such individual's bonus entitlement or profit share for such year.

The Corporation establishes an account for each Participant and all DSUs are credited to the applicable account as of the award date. The number of DSUs to be credited to an account is determined by dividing the dollar amount elected by the Participant by the five-day weighted average closing price of the Common Shares on the TSX immediately prior to the award date. On the last day of each fiscal quarter of the Corporation or as soon as possible thereafter, the Corporation determines whether any dividend has been paid on Common Shares during such fiscal quarter and, if so, the rate thereof per Common Share (the "**Dividend Rate**") and, within 10 business days of the applicable fiscal month end, the Corporation credits each applicable account with an additional number of Units equal to (i) the number of DSUs in the applicable account on the record date for such dividend multiplied by (ii) the Dividend Rate. All DSUs vest immediately upon being credited to a Participant's account.

A Participant is not entitled to any payment of any amount in respect of DSUs until such Participant ceases to be an employee or director of the Corporation, as the case may be, for any reason whatsoever. Upon the Participant ceasing to be an employee or director of the Corporation, the Participant is entitled to receive a lump sum cash payment, net of applicable withholding taxes, equal to the product of (i) the number of DSUs in such Participant's account on the date the Participant ceased to be an employee or director and (ii) the five-day weighted average closing price of the Common Shares on the TSX immediately prior to such date, unless the redemption event occurs during a blackout period, in which case the amount of such payment will be calculated with reference to the five-day weighted average closing price of the Common Shares on the TSX on the fifth business day following the end of such blackout period. The Corporation will make such lump sum cash payment by the end of the calendar year following the year in which the Participant ceased to be an employee or director.

On March 10, 2015, the Board amended the DSU Plan to include provisions that govern citizens and residents in conformity with Section 409A of the U.S. Internal Revenue Code. This amendment was made to clarify and explicitly disclose certain tax consequences associated with participation in the DSU Plan by eligible U.S. citizens and U.S. residents.

The Corporation had 1,951,870 DSUs outstanding at December 31, 2024.

PSU Plan

In 2017, the Corporation adopted the PSU Plan, which is administered by the Board of Directors. The purposes of the PSU Plan are: (i) to promote alignment of interests between participants in the PSU Plan and Shareholders by providing the participants with an opportunity to participate in an increase in the equity value of the Corporation, taking into account the performance of the Corporation relative to its peers and targets established by the Board; (ii) to provide participants in the PSU Plan with compensation reflective of their responsibility, commitment and risk accompanying their role over the long-term; and (iii) to provide a retention incentive to participants in the PSU Plan over the long-term. Under the terms of the PSU Plan, the Compensation Committee may designate employees of the Corporation or its affiliates who are eligible to receive performance share units ("**PSUs**"). PSUs are notional grants of share-based compensation units that entitle the holder to a cash payment upon redemption of the PSU.

Unlike Restricted Shares, PSUs do not automatically vest over time. Instead, vesting is dependent on the achievement of various corporate performance metrics over a three-year performance period.

The vested number of PSUs relating to a given performance period are paid out in cash based on the volume weighted average trading price of the Common Shares on the TSX over the five business days subsequent to the end of the performance period for the applicable PSUs, plus the dividends paid during the applicable performance period. For PSUs that were granted in 2023 or later, the vested number of PSUs relating to a given performance period are paid out in cash based on the volume weighted average trading price of the Common Shares on the TSX over the five business days subsequent to the end of the performance period for the applicable PSUs. Dividends paid during the applicable performance period are reinvested in additional PSUs, which vest on the vest date of the original grant.

Based on underlying units prior to any effect of the performance multiplier, the Corporation had 2,106,192 PSUs outstanding at December 31, 2024.

Stock Option Plan

The Corporation has made no stock option ("**Options**") grants since 2021 and does not intend to grant Options in the future.

The Corporation adopted the Stock Option Plan in early 2018, with the purpose of rewarding those persons who promote the growth and success of the Corporation and assisting the Corporation in attracting, motivating and retaining personnel. The Stock Option Plan was approved by the Shareholders at the Corporation's annual meeting of shareholders on May 4, 2018 and amended to reduce the maximum number of Common Shares issuable under the Stock Option Plan at the Corporation's annual meeting of shareholders on May 14, 2020.

Pursuant to the terms of the Stock Option Plan, a maximum of 10,000,000 Common Shares may be issuable upon the exercise of Options granted under the Stock Option Plan (subject to adjustment for any subdivision or consolidation of the Common Shares). As at December 31, 2024, there were 713,876 Options to purchase Common Shares outstanding. Additionally, the number of Common Shares issuable to insiders of the Corporation (as defined in the Company Manual of the TSX) in any one year period, or at any time when combined with Common Shares issued or issuable under any of the Corporation's other security-based compensation plans, may not exceed 10% of the issued and outstanding Common Shares, and no one insider (or associates of that insider, as defined in the Company Manual of the TSX) may be issued more than 5% of the issued and outstanding Common Shares in any one year period. Non-employee directors are not entitled to participate in the Stock Option Plan. No Options shall be granted to any participant if the total number of Common Shares issuable to or on behalf of such participant under the Stock Option Plan, together with any Common Shares reserved for issuance to such participant under any other share compensation or incentive mechanism of the Corporation (which includes restricted share units issued under the Restricted Share Bonus Plan) would exceed 5% of the aggregate issued and outstanding Common Shares.

The Board of Directors administer the Stock Option Plan and will from time to time designate officers and employees of the Corporation who are entitled to participate in the Stock Option Plan, and determine the number and exercise price of Options to be granted to such participants. Non-employee directors are prohibited from participating in the Stock Option Plan. Under the Stock Option Plan, the exercise price of Options is determined by the Board of Directors at the time of grant but will not be less than permitted by the applicable rules and policies of the TSX. Subject to the vesting provisions of the Stock Option Plan, Options may be: (i) exercised by paying the Corporation the exercise price in exchange for Common Shares; (ii) surrendered to the Corporation in exchange for a cash payment representing the aggregate difference between the market price of the Common Shares and the exercise price of the Options surrendered; or (iii) surrendered to the Corporation in exchange for a number of Common Shares equivalent in value (based on the market price) to the aggregate difference between market price of the Common Shares and the exercise price of the Options surrendered.

Unless the Board of Directors determine otherwise, Options granted pursuant to the Stock Option Plan will have a term of seven years, subject to early expiry in accordance with the change in control and other provisions of the Stock Option Plan. All Options are granted pursuant to stock option agreements executed at the time of grant by the Corporation and the grantee.

Employee Share Value Plan

In early 2020, the Corporation adopted an Employee Share Value Plan ("**ESVP**") for certain employees in lieu of grants that would have previously been made under the Restricted Share Bonus Plan. Under the terms of the ESVP, any employee of the Corporation who, in each case, in the opinion of the Board of Directors, holds an appropriate position with the Corporation to warrant participation in the ESVP (collectively, the "**ESVP Participants**") may be granted rights ("**Awards**") which vest over time and, upon vesting, entitle the participant to receive a cash payment for each Award equal to the five day weighted average trading price on the TSX of the Common Shares immediately preceding the vesting date plus an amount equal to the aggregate amount paid by the Corporation in dividends per Common Share from the grant date of an Award to and including the vesting date (collectively, the "**Payout Value**"). ESVP Participants do not have any right to receive Common Shares in respect of vested Awards.

Awards vest as to 33 1/3% on each of the first, second and third anniversaries of the grant date as determined by the Board of Directors. Upon vesting of an Award, the Corporation is required to pay to an ESVP Participant the Payout Value within 15 business days of vesting and, in all cases, prior to December 31 of the year of vesting.

The Employee Share Value Plan is administered by the Board of Directors. At December 31, 2024, there were 2,848,960 awards outstanding.

Long-Term Debt - Bank Debt

At December 31, 2024, the Corporation had combined revolving facilities (the "**Credit Facilities**") of $2.36 billion.

The revolving Credit Facilities include a $2.26 billion syndicated unsecured credit facility (the **Syndicated Credit Facility**") and a $100.0 million unsecured operating credit facility (the "**Bi-Lateral Credit Facility**"), both with a current maturity date of November 26, 2028.

The Syndicated Credit Facility and the Bi-Lateral Credit Facility's interest rate is based on either Canadian prime rate, U.S. base rate, secured overnight financing rate or Canadian Overnight Repo Rate Average ("CORRA") rates at the Corporation's option subject to certain basis point or stamping fee adjustments of up to 2.25%, depending on the Corporation's rating. The Credit Facilities are guaranteed by certain restricted subsidiaries currently being VERUS, VHL and the Partnership. Various borrowing options are available under the Credit Facilities, including Canadian prime rate-based advances, U.S. base rate-based advances, secured overnight financing rate loans and CORRA loans. The Syndicated Credit Facility and Bi-Lateral Credit Facility constitute revolving credit facilities and are extendible annually. The Credit Facilities contain standard commercial covenants for facilities of this nature. Distributions to Shareholders and share repurchases are not permitted if the Corporation is in default of the Credit Facilities or if the making of such distribution would cause an event of default. The Corporation does not have a borrowing base restriction respecting its Credit Facilities.

At December 31, 2024, the Corporation had available unused borrowing capacity on its revolving Credit Facilities of approximately $1.45 billion, including cash of $17.1 million.

The Corporation has a $60.0 million unsecured demand letter of credit facility. The Corporation had letters of credit in the amount of $43.0 million outstanding at December 31, 2024.

Long-Term Debt - Senior Notes

At December 31, 2024, the Corporation had approximately $1.54 billion of senior notes (the "**Senior Notes**") outstanding, consisting of private senior notes and public senior notes, of which $514.4 million become due within one year excluding the value of underlying cross currency swaps. The Senior Notes are unsecured and rank pari passu with the Corporation's Credit Facilities and carry a bullet repayment on maturity. The private senior notes have financial covenants similar to those of the Credit Facilities described above. There are no financial covenants associated with the public senior notes.

At December 31, 2024, the Corporation had outstanding private senior notes of US$332.0 million and Cdn$65.0 million. Concurrent with the issuance of the U.S. denominated private senior notes, the Corporation entered into cross currency swaps to manage its foreign exchange exposure, fixing the US dollar amount of certain tranches of notes, for purposes of interest and principal repayments, at a notional amount of $330.5 million.

At December 31, 2024, the Corporation had outstanding investment grade public senior notes of $1.00 billion, consisting of $550.0 million of 4.968% notes priced at par and due June 2029, and $450.0 million of 5.503% notes priced at par and due June 2034.

Credit Ratings

Veren's credit rating of BBB (low) with a stable trend addresses Veren's ability to obtain short-term and long-term financing and the cost of such financing. Changes in credit rating may affect the Corporation's ability to access to sources of liquidity and capital.

That credit rating was provided by credit rating agency Morningstar DBRS ("**DBRS**"). Entities in the BBB (low) category are of adequate credit quality; however, they may be vulnerable to future events. DBRS has ten rating categories for long-term debt and long-term issuer credit ratings, which range from "AAA" to "D". DBRS uses "(high)" and "(low)" designations on ratings from "AA" to "CCC" to indicate the relative standing within a particular rating category. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category. The assignment of a "(low)" modifier indicates the rating is in the lower end 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 by the issuer.

Each year Veren pays DBRS an annual fee in connection with assessing and maintaining their corporate credit rating.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas entities of similar size. All current legislation is a matter of public record, and we are unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing - Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers. Oil prices are primarily based on worldwide and North American supply and demand. The specific price paid depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance.

Oil exports from Canada may be made pursuant to an export contract with a term not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the Canada Energy Regulator (the "**CER**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the CER and the issue of such a license requires the approval of the Governor in Council.

In the United States, transportation of crude oil is subject to rate and access regulation. The Federal Energy Regulatory Commission (the "**FERC**") regulates interstate crude oil pipeline transportation rates under the *Interstate Commerce Act* of 1887 (the "**ICA**"). In general, such pipeline rates must be cost-based. The FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service. Such rates and terms and conditions may not be discriminatory or preferential. A pipeline may also file cost-of-service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Intrastate crude oil pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state.

Most exports of U.S. produced crude oil may be made without an export license. Only exports to embargoed or sanctioned countries continue to require authorization from the U.S. Department of Commerce.

Pricing and Marketing - Natural Gas

In Canada, the price of natural gas sold intra-provincially or to the United States is determined by negotiation between buyers and sellers. In the United States, the price of inter-state or international sales is determined by negotiation between buyers and sellers based upon factors normally considered in the industry such as distance from well to pipeline, pressure, and quality. Natural gas exported from Canada is subject to regulation by the CER and the Government of Canada, and in the United States is regulated principally by the FERC and the United States Department of Energy (the "**DOE**"). The FERC, which has the authority under the *Natural Gas Act* of 1938 (the "**NGA**") to regulate prices, terms and conditions for the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to FERC regulation, except interstate pipelines, to resell natural gas at market prices. In addition, under the provisions of the *Energy Policy Act* of 2005, the NGA was amended to prohibit market manipulation in connection with the purchase or sale of natural gas and the FERC established regulations to increase natural gas pricing transparency by requiring certain market participants to report their gas sales transactions annually to the FERC. Facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Although FERC has set forth a general test to determine whether facilities are exempt from FERC jurisdiction as "gathering" facilities, FERC's determinations as to the classification of facilities are performed on a case-by-case basis and FERC has the authority to reclassify facilities previously thought to be non-jurisdictional. The FERC regulates interstate natural gas transportation rates and service conditions under the NGA and the *Natural Gas Policy Act* of 1978 (the "**NGPA**"), which affects the marketing of natural gas, as well as revenues we may receive for sales of our natural gas. Intrastate natural gas transportation service is also subject to regulation by state regulatory agencies.

In both Canada and the United States, exporters are free to negotiate prices and other terms with purchasers, provided that the export contract meets certain criteria prescribed by the CER and the Government of Canada or, in relation to United States exports, restrictions on export licenses imposed by the DOE. Natural gas may not be exported from Canada without a license or order from the CER or imported into the United States or exported from the United States without a license from the DOE. Licenses to export or import natural gas may include various terms and conditions with respect to duration, quantity, tolerance levels, points of exportation or importation, environmental requirements, among other factors and, in Canada, for export, may be obtained for a period that does not exceed 40 years. In Canada the approval of the Minister of Natural Resources and the Governor in Council is currently required prior to the issuance of a license to export natural gas. Alternatively, natural gas may be exported from Canada pursuant to an order from the CER. Orders may be obtained for a period of two years or less or for a period greater than two years but less than 20 years, where the quantity is not more than 30,000 m^3/day. Orders do not require the approval of the Governor in Council or the Minister of Natural Resources. Any person who imports oil or gas into Canada must provide prescribed information in the prescribed form and manner to the CER, but does not require a license. In the United States, the DOE regulates the exportation and importation of natural gas, including liquefied natural gas. U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a free trade agreement with the United States that provides for national treatment of trade in natural gas, however, the DOE's regulation of imports and exports from and to countries without such free trade agreements is more comprehensive. The FERC also regulates the construction and operation of import and export facilities.

The Canada-United States-Mexico Agreement and The North American Free Trade Agreement

On July 1, 2020, the Canada-United States-Mexico Agreement ("**CUSMA**") came into force, replacing the North American Free Trade Agreement ("**NAFTA**").

Relevant to the energy industry, CUSMA does not contain the proportionality rules found in NAFTA's Article 605 whereby Canada remained free to restrict exports to the U.S. or Mexico provided that such export restrictions did not: (i) reduce the proportion of the energy resource exported relative to the total supply of that energy resource in Canada as compared to the proportion prevailing in the most recent 36-month period; (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply.

CUSMA also eliminated certain tariffs on some diluents used to transport heavy oil from Canada to the U.S.

There has been little to no effect on Canada's energy industry by the ratification of CUSMA and Veren has experienced little to no change to its operations or marketing activities due to the ratification of CUSMA.

CUSMA is set to expire 16 years after coming into force on June 30, 2036. The agreement includes a requirement for a formal review at least every six years, and the next review is scheduled for 2026. U.S. President Trump has indicated that he would renegotiate the agreement.

Royalties and Incentives

In addition to federal regulation, each province where we operate has legislation with respect to oil and gas activities, governing matters such as land tenure, royalties, production rates, environmental protection and other matters. In all Canadian jurisdictions where we operate, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity and depth, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the governments of Canada, Alberta and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced production projects. Such programs are generally introduced when commodity prices are low and are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. These programs reduce the amount of Crown royalties otherwise payable.

Alberta

In terms of oil or natural gas production from Crown lands, royalties are payable to the Province of Alberta. In respect of freehold lands, royalties are payable to the mineral owner and taxes are payable to the Province of Alberta. The Government of Alberta's approach to the royalty and tax regime is regularly reviewed for compliance with the purpose of the regimes to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees.

On January 1, 2017, Alberta adopted a new, modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "**Old Framework**") continues to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

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

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward as the mature well's production declines.

As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low-cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional oil production under the Old Framework range from a base rate of zero to a cap of 40%.

The Old Framework also includes a natural gas royalty formula, which formula provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%.

Under the Old Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

In terms of oil and natural gas production obtained from lands other than Crown lands, taxes are payable to the Province of Alberta. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the Alberta Crown. The tax levied in respect of freehold oil and gas production in the Province of Alberta is calculated annually based on a rate dependent on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

Incentive Programs

A number of incentive programs, including the Enhanced Oil Recovery Royalty Program (the "**EOR Program**") were created pursuant to the Old Framework.

Under the EOR Program, Alberta Energy and Minerals may approve royalty reductions for qualifying enhanced oil recovery projects. Applications under the EOR Program ceased being accepted as of December 31, 2016, however, the EOR Program continues to apply to schemes previously approved thereunder, and will continue to apply until December 31, 2026.

Under the Modernized Framework, two strategic programs were introduced with the intention of promoting expanded production potential and generating long-term returns to the Province of Alberta.

The Enhanced Hydrocarbon Recovery Program (the "**EHR Program**") began January 1, 2017, and replaced the EOR Program. The EHR Program is intended to promote incremental production through enhanced recovery methods and consists of two main components. The first component targets tertiary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by miscible flooding, immiscible flooding, solvent flooding, chemical flooding or other approved methods. The second component targets secondary recovery schemes which enhance recovery of hydrocarbons from an oil or gas pool by waterflooding, gas cycling, gas flooding, polymer flooding or other approved methods. Under both components of the program, a company pays a flat royalty of 5% on crude oil, natural gas and natural gas liquids produced from wells in an approved scheme for a limited benefit period. After the benefit period ends, wells in these schemes are subject to normal royalty rates under the Modernized Framework.

The Emerging Resources Program (the "**ERP**") began January 1, 2017. The ERP is intended to encourage industry to open up new oil and gas resources in higher-risk and higher-cost areas that have large resource potential. For the purposes of the ERP, a project consists of a defined geographic area, target formation, set of wells and associated infrastructure. Wells that receive program benefits pay a flat royalty rate of 5% on revenues until their combined revenue equals their combined program specific cost allowances established under the ERP, which replace the standard "Drilling and Completion Cost Allowance" under the Modernized Framework in respect of such wells. After achieving payout of the specific cost allowance, wells are subject to normal royalty rates under the Modernized Framework.

Saskatchewan

With respect to production obtained from provincial Crown lands in the Province of Saskatchewan, the amount payable as a royalty in respect of crude oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month and the price of the oil. For both Crown royalty and freehold production tax purposes, crude oil is categorized by oil type as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". Additionally, the oil in each category is subdivided according to the conventional royalty and production tax classifications as "fourth tier oil", "third tier oil", "new oil", or "old oil". The royalty reserved to the Crown depends on the categorization and classification of the oil, monthly production, and a prescribed reference price determined monthly by the Saskatchewan Ministry of Energy and Resources ("**SMER**").

Similarly, the amount payable as a royalty in respect of natural gas in the Province of Saskatchewan depends on the vintage of the gas, the type of gas production, the quantity of gas produced in a month, and the price of the gas. For both provincial Crown royalty and freehold production tax purposes, natural gas is categorized as either non-associated gas or associated gas, the former being gas produced from gas wells and the latter being gas produced from oil wells. Additionally, the gas is divided according to the royalty and production tax classifications as "fourth tier gas", "third tier gas", "new gas", or "old gas". The royalty reserved to the Crown depends on the categorization and classification of the natural gas, monthly production, and a reference price prescribed by the SMER. As an incentive for the production and marketing of natural gas which may otherwise have been flared, the royalty rate on associated gas is less than on non-associated natural gas.

Approximately 17% of the mineral rights in the Province of Saskatchewan are freehold mineral rights not owned by the provincial Crown. With respect to production from freehold lands, the tax levied on oil and gas production in the Province of Saskatchewan will depend on the classification of the oil or gas and the relevant Crown royalty rate.

Incentive Programs

On October 1, 2002, a modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from qualifying oil wells and gas wells in the Province of Saskatchewan with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%. In addition, oil produced from Enhanced Oil Recovery ("**EOR**") projects that commenced operation prior to April 1, 2005 are subject to a cost sensitive royalty regime determined by prescribed formulas which include a number of variables, and which differentiate between pre- and post-project payout. EOR projects that commenced operation on or after April 1, 2005 are also subject to a cost sensitive royalty regime that provides a royalty of 1% of gross EOR revenues prior to project payout and 20% of EOR operating income after project payout and a freehold production tax rate of 0% prior to payout and 8% of EOR operating income after payout. In respect of new waterflood projects, or expansions of existing waterflood projects, that have been approved by the minister and that commenced operation on or after October 1, 2002, the incremental oil produced from the project as a result of the waterflood operations qualifies for the "fourth tier oil" Crown royalty and freehold production tax rates.

In April of 2013, the SMER announced three new drilling incentives for wells drilled on or after October 1, 2002: the vertical well drilling incentive (the "**VWDI**"); the horizontal well drilling incentive (the "**HWDI**"); and the exploratory gas well drilling incentive (the "**EGWDI**"). The VWDI provides a Crown royalty reduction to 2.5% and a freehold production tax rate of 0% for fixed volumes drilled from exploratory vertical oil wells and deep development vertical oil wells. Exploratory vertical oil wells are wells that meet certain prescribed criteria showing the well produces oil from an area which has not generally seen production. The incentive for exploratory vertical oil wells applies to the produced volume up to 16,000 m^3, depending on depth. Deep development vertical oil wells are deep or deepened wells, that are not exploratory oil wells, drilled to certain prescribed zones. The incentive for these wells applies to the produced volume up to 8,000 m^3. The HWDI is very similar to the VWDI, but applies to non-exploratory horizontal wells drilled on or after October 1, 2002 and provides the incentive to produced volumes up to 16,000 m^3, depending on depth. Finally, the EGWDI provides a royalty reduction of the lesser of the fourth tier gas royalty rate (between 0%-5%) or 2.5% and a 0% freehold production tax rate. The incentive applies to wells that meet certain prescribed criteria which show that the well produces gas from an area from which gas has not generally been produced. The incentive applies to the produced volume up to 25,000,000 m^3.

In December 2018, the Government of Saskatchewan introduced the Waterflood Development Program (the "**WDP**"), which program offers repayable royalty and freehold production tax deferrals for eligible wells that have been converted to injection wells or newly drilled injection wells for the purpose of waterflooding an oil reservoir. Under the WDP, royalty and freehold production taxes can be deferred for a period of three years and can be used alongside other incentive grant programs available in Saskatchewan.

In June of 2019, the Government of Saskatchewan introduced the Saskatchewan Petroleum Innovation Incentive (**SPII**"). SPII offers transferable royalty and freehold production tax credits for qualified innovation commercialization projects at a rate of 25% of eligible project costs, targeting a broad range of innovations across all segments of Saskatchewan's oil and gas industry. The SPII is in place until March 31, 2029, and may be subject to further extension by the Government of Saskatchewan.

On August 1, 2019 the Government of Saskatchewan introduced the Oil and Gas Processing Investment Incentive (**OGPII**"). OGPII offers transferable royalty and freehold production tax credits for qualified greenfield or brownfield value-added projects at a rate of 15% of eligible project costs. The OGPII is in place until March 31, 2029, and may be subject to further extension by the Government of Saskatchewan.

In March 2020, the Government of Saskatchewan introduced the Oil Infrastructure Investment Program (**OIIP**"), which program offers transferable oil and gas royalty and freehold production tax credits for qualified projects at a rate of 20% of eligible project costs (with a minimum $10 million investment). OIIP is open to new or expanded oil, refined petroleum products or natural gas liquids, including transmission pipelines, feeder pipeline and pipeline terminals. As of November 4, 2021, carbon dioxide pipeline projects became eligible for OIIP, including pipeline projects to be used for transporting carbon dioxide for carbon capture and storage or for EOR projects.

Effective April 1, 2021, Saskatchewan amended the High Water-Cut Oil Well Program, which program provides a royalty status re-assignment for qualifying high water-cut oil wells that incur an average minimum investment of $20,000 per well, made on or after April 1, 2021, to directly improve water handling capabilities and extend the producing life of the well. Such eligible wells drilled before October 1, 2002 will receive fourth tier royalties on all future incremental high water-cut oil production, and wells drilled on or after October 1, 2002 will obtain a 2% royalty rate reduction on all future oil production.

On April 6, 2021, the Government of Saskatchewan introduced the Associated Gas Royalty Moratorium, which is a moratorium on the collection of Crown royalty and freehold production tax on associated gas produced from wells other than gas wells, including natural gas produced from oil wells. The moratorium has been implemented as part of Saskatchewan's Methane Action Plan to assist producers in meeting regulatory obligations to reduce methane-based greenhouse gas emissions by 40-45% between 2020 and 2025. The moratorium applies to associated natural gas produced on or after April 1, 2021, and before April 1, 2026.

On March 20, 2024, the Government of Saskatchewan announced the Multilateral Oil Well Program (**MLWP**") as part of the SMER's 2024-2025 budget. The MLWP offers a volumetric drilling incentive for eligible multi-lateral horizontal oil wells drilled on or after April 1, 2024, and on or before March 21, 2028. The incentive amount depends on the number of lateral wells drilled. With respect to the royalty applied to oil produced from or allocated to Crown lands, a Crown royalty rate equal to the lesser of: (a) the "fourth tier oil" Crown royalty rate; and (b) 2.5% will apply. A production tax rate of 0% will be applied to oil produced from or allocated to freehold lands.

Environmental Regulation and Protection Requirements

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to international conventions and national, provincial, state, territorial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, discharges, or emissions of various substances produced or used in association with oil and gas operations, as well as requirements with respect to oilfield waste handling, storage and disposal, land reclamation, habitat and endangered species protection, and minimum setbacks of oil and gas activities from sensitive receptors.

Provincial environmental legislation in the Province of Alberta for the oil and gas industry is, for the most part, set out in the *Environmental Protection and Enhancement Act*, the *Oil and Gas Conservation Act*, the *Pipeline Act*, the *Water Act, the Public Lands Act* and the *Technology and Emissions Reductions Implementation Act, 2019,* which impose strict environmental standards with respect to releases of effluents and emissions, including monitoring and reporting obligations, and impose significant penalties for non-compliance. Provincial environmental legislation in the Province of Saskatchewan is, for the most part, set out in *The Environmental Management and Protection Act, 2010*, *The Saskatchewan Environmental Code, The Oil and Gas Conservation Act*, *The Pipeline Act, 1998* and *The Management and Reduction of Greenhouse Gases Act* which regulate harmful or potentially harmful activities and substances and GHGs, any release of such substances, and remediation and abandonment obligations in Saskatchewan. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require an environmental impact assessment under the provincial *Environmental Assessment Act*. Provincial environmental legislation in the Province of Manitoba is, for the most part, set out in the *Environment Act* and the *Oil and Gas Act*.

Environmental legislation also requires that wells, pipelines and facility sites be constructed, operated, maintained, abandoned, and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, or in the suspension or revocation of necessary licenses and approvals. Veren may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject Veren to statutory strict liability in the event of an accidental spill or discharge from a well, pipeline or facility, meaning that fault on the part of Veren need not be established if such a spill or discharge is found to have occurred.

Veren estimates abandonment and reclamation costs by taking into consideration the costs associated with decommissioning, abandonment, remediation and reclamation, all adjusted according to its working interest and discounted in accordance with NI 51-101. Decommissioning liability cost estimates are based on information published by the AER with respect to the AER liability management programs in Alberta and published by SMER in Directive PNG025 Financial Security Requirements Saskatchewan. Veren has procedures in place which address various matters including: spill prevention, response, notification, reporting, remediation and reclamation; environmental monitoring; government inspections; surface equipment spacing requirements; facility protection/security; vegetation management; surface water run-off/run-on management; groundwater; noise control; atmospheric emissions; wellsite reclamation; earthen pits; storage tanks; naturally occurring radioactive materials; disposal wells; suspended or shut-in wells; waste management; and communications.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability, and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil, or water may give rise to liabilities to third parties or regulators or result in the suspension or revocation of regulatory approvals and may require Veren to incur costs to remedy such a discharge in an event not covered by Veren's insurance, which insurance is in line with industry practice. Furthermore, Veren expects incremental future costs associated with compliance with increasingly complex environmental protection requirements with respect to GHG emissions or otherwise, some of which may require the installation of emissions monitoring and measuring devices, the verification and reporting of emissions data and additional financial expenditures to comply with GHG emissions reduction requirements.

Greenhouse Gas Emissions

Carbon Policy

In November 2015, Canada participated in the twenty first session of the Conference of the Parties of the United Nations Framework Convention on Climate Change ("**COP 21**") in Paris, France, the goal of which was to reach a new agreement for fighting global climate change. COP 21 resulted in the adoption of the Paris Agreement which made several recommendations, including: (i) holding the increase in the global average temperature to well below 2 °C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5 °C above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change; (ii) increasing the ability to adapt to the adverse impacts of climate change and fostering climate resilience and low greenhouse gas emissions development, in a manner that does not threaten food production; and (iii) making finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development. The Paris Agreement came into force on November 4, 2016.

Over the last several years, the federal government has undertaken a number of initiatives to achieve domestic GHG reductions that align with its commitments made under the Paris Agreement. These measures include regulations, codes and standards, targeted investments, incentives, tax measures and programs intended to directly and indirectly reduce GHG emissions.

On June 21, 2018, the Government of Canada brought into force a pan-Canadian approach to the pricing of GHG emissions under the *Greenhouse Gas Pollution Pricing Act* ("**GGPPA**"). The federal carbon pollution pricing system has two parts: (i) an emission reduction and trading system for large industry, known as the output-based pricing system ("**OBPS**"); and (ii) a regulatory charge on 21 types of fuel, commonly known as the carbon tax. Each province was given the choice to either accept the federal requirement in full; create their own carbon pricing policies that meet federal standards; or a hybrid approach. Both Saskatchewan and Alberta have opted for the hybrid approach, where they have committed to develop province specific output-based pricing systems but are subject to the federal carbon tax on fuel. The federal carbon tax is applied on a broad set of fuels at $80 per tonne of GHG emissions in 2024 and will increase to $95 per tonne in 2025 and then by $15 per tonne per year until it reaches $170 per tonne in 2030.

The federal government also has a GHG emission reporting requirement under the *Canadian Environmental Protection Act, 1999* ("**CEPA**") whereby facilities that emitted 10,000 tonnes or more of GHGs per year must report their emissions to Environment and Climate Change Canada. On June 21, 2022, the federal government also brought into force the *Clean Fuel Regulations* which set emission limits on a variety of liquid fuels, including gasoline and diesel.

On November 9, 2024, the Government of Canada published for public consultation draft *Oil and Gas Sector Greenhouse Gas Emissions Regulations* that will, if enacted, set emissions limits from upstream oil and gas facilities that will be phased in between 2026 and 2030. The proposed Regulations includes a proposed cap and trade system whereby emission allowances issued or auctioned by the federal government will be tradeable among upstream oil and gas facilities. In addition, it is proposed that facilities will be able to use both emission offset credits created under other federal or provincial emission reduction systems and payments made to a decarbonization fund to meet the emissions cap. The proposed Regulations would allow up to a maximum of 20% over the emissions allowance cap to be offset by credits or paying into the decarbonization fund. Final regulations setting the emissions cap system are expected to be published in mid-2025.

In Alberta, GHG emissions are regulated under the *Emissions Management and Climate Resilience Act* and the TIER Regulation, which came into effect January 1, 2020. The TIER system is mandatory for large emitters, being those that emit 100,000 tonnes or more of GHGs per year, however, facilities with less than 100,000 tonnes per year can voluntarily opt into the system by aggregating two or more smaller facilities together. Registered facilities are required to reduce their emission intensity (tCO2e/boe) by 10% based on a historical benchmark. Companies may meet these required reductions through improvements to their operations; by purchasing and retiring Alberta-based emission reduction or offset credits; by contributing to the provincial TIER Compliance Fund; or by a combination of these actions. Any facility registered into the TIER system can apply to the Canadian Revenue Agency and receive an exemption from the federal fuel surcharge (carbon tax) on applicable fuel combustion and flaring. Veren has three aggregate facilities registered in the TIER system.

On December 15, 2022, the Government of Alberta announced amendments to TIER, which became effective on January 1, 2023, which amendments include meeting federal emission reduction requirements for 2023 through 2030, compliance flexibility and increasing the regulator stringency.

On January 1, 2019, the Government of Saskatchewan brought into force *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations* (the "**MRGHGR**") to regulate greenhouse gas emissions in the province. As part of the MRGHGR, the Output-Based Performance Standards ("**the Saskatchewan OBPS**") were developed to reduce emissions intensity associated with stationary fuel combustion by 15% by 2030, however, subsequently, effective January 1, 2023, emissions intensity associated with stationary fuel combustion and flaring were reduced by 20% by 2030. Under the Saskatchewan OBPS program operators of certain large facilities that emit 25,000 tonnes or more of GHGs per year must register. Additionally, a voluntary aggregated facility (two or more smaller facilities grouped together) can also register in the OBPS program. Operators must reduce their emissions per unit of production from their historical emissions and may meet these required reductions through improvements to their operations; by purchasing and retiring emission reduction or offset credits; by contributing to the provincial Technology Fund; or by a combination of these actions. Any facility registered in the Saskatchewan OBPS can apply to the Canadian Revenue Agency and receive an exemption from the federal fuel surcharge (carbon tax) on applicable fuel combustion. Veren has one aggregate facility registered in the Saskatchewan OBPS program.

The U.S. initially entered into the Paris Agreement, but on June 1, 2017, President Trump announced that the United States intended to withdraw from the Paris Agreement, and the withdrawal became effective on November 4, 2020. On January 20, 2021, President Biden signed an executive order to rejoin the Paris Agreement, which the U.S. officially rejoined on February 19, 2021. Additionally, the Inflation Reduction Act of 2022 included several measures designed to combat climate change, including restrictions on methane emissions. On January 20, 2025, President Trump announced an intention to withdraw from the Paris Agreement.

On March 6, 2024, the SEC adopted the Final Rule for the Enhancement and Standardization of Climate-Related Disclosures for Investors. This rule would have affected both U.S. issuers and foreign private issuers (filing on Form 20-F), but would not have applied to Canadian issuers that file their Exchange Act registration statements and annual reports on Form 40-F, such as the Corporation. On April 4, 2024, the SEC issued an order staying this rule until the completion of litigation filed in the federal courts that challenge the agency's authority to adopt these rules.

Methane Policy

On June 29, 2016, Canada joined the United States and Mexico in agreeing to reduce methane emissions from the oil and gas sector by up to 45% by 2025 from 2014 levels by developing and implementing federal regulations for both existing and new sources of venting and fugitive methane emissions. Previously, on March 10, 2016, Canada and the United States committed to take action on methane emissions through federal regulations as expeditiously as possible. The United States has since cancelled their participation in this initiative.

On January 1, 2020, the Canadian federal government implemented the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*.

The federal regulations that apply to methane in the upstream oil and gas sector aim to control methane emissions and also reduce the amount of volatile organic compounds released into the air. These regulations apply generally to facilities that handle significant volumes of gas (facilities that produce or receive a combined volume of 60,000 m^3 of hydrocarbon gas or greater annually in any of the past five years). The regulations outline regulatory requirements for fugitive equipment leaks, venting from well completions, and compressors, which came into force on January 1, 2020, and requirements for facility production venting restrictions and venting limits for pneumatic equipment, which come into force on January 1, 2023.

Operators of upstream oil and gas facilities are required to: implement a leak detection and repair program to stop natural gas leaks three times per year on facilities that produce or receive a combined volume of 60,000 m^3 of hydrocarbon gas or greater annually; complete annual measurements of emissions from natural gas compressor vents to ensure emissions are under the applicable limit; and eliminate venting from well completions involving hydraulic fracturing.

Beginning in 2023, operators of upstream oil and gas facilities were required to: meet a venting limit of 15,000 m^3 of gas per year at facilities that produce and/or receive more than 60,000 m^3 of gas per year, and limit venting from pneumatic devices to a maximum threshold.

All upstream oil and gas facilities to which the federal regulations apply are required to register and to keep records to demonstrate compliance with the proposed regulations. Facility operators are also required to submit reports at the request of the federal Minister of Environment.

On October 11, 2021, the Canadian federal government announced its support for the Global Methane Pledge, which aims to reduce global methane emissions by 30 percent below 2020 levels by 2030. In support of the Global Methane Pledge, Canada announced its commitment to developing a plan to reduce methane emissions across the broader Canadian economy and to reducing oil and gas methane emissions by at least 75 percent below 2012 levels by 2030, and that these goals will be achieved through an approach that will include regulation.

In September 2022, the Government of Canada released Canada's Methane Strategy with the aim of reducing domestic methane emissions, including a new target of reducing absolute methane emissions from the oil and gas sector by 75% by 2030 relative to 2012. In November 2022, the Government of Canada released a Proposed Regulatory Framework for Reducing Oil and Gas Methane Emissions to Achieve 2030 Target. The proposed changes will expand the scope of the existing regulations to apply to a wider set of sources, including all facilities handling natural gas, increasing the scope and frequency of inspection programs, requiring certain non-emitting equipment when feasible, prohibiting flaring at oil sites, limiting venting of methane and requiring fugitive methane emissions management plans.

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

Currently the federal regulations do not apply in provinces which the federal government deems to have equivalent methane reduction regulations. Alberta, Saskatchewan and British Columbia have each reached equivalency agreements with the federal government and currently operators in these provinces are subject to only the provincial methane reduction requirements.

In Alberta, design specifications have been put in place by the AER for oil and gas wells, pipelines and facilities as well as standards for key equipment and operational best practices. Fugitive emission standards are also included in the regulatory requirements and will raise current standards for performance, monitoring, measurement and reporting. The AER has published directives requiring methane emission reductions.

On January 1, 2019, the Government of Saskatchewan brought into force *The Oil and Gas Emissions Management Regulations* to reduce methane emissions from upstream oil and gas companies with emissions of more than 50,000 tonnes of GHGs per year from oil facilities. Every company subject to the regulation must follow a methane emission reduction plan approved by the SMER and must ensure GHG emissions from flaring and venting are below provincial limits or pay an administrative penalty if they fail to do so.

Veren's operations are subject to costs being incurred to comply with carbon taxes, GHG emission reduction requirements, including methane emission reductions, and to preform necessary monitoring, measurement, verification and reporting of GHG emissions.

Veren anticipates current and future environmental legislation will require reductions in emissions from its operations and result in increased capital and operational expenditures. Further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liability and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition and results of operations.

We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures due to the increasingly stringent laws relating to the protection of the environment. Our internal procedures are designed to ensure that the environmental aspects of new developments are considered prior to proceeding.

Abandonment and Reclamation Costs

As of December 31, 2024, Veren owned approximately 10,139 gross (8,922.8 net) producing, non-producing and abandoned wells for which abandonment and/or reclamation costs are expected to be incurred. During 2024, Veren spent approximately $40.6 million on well abandonment and environmental reclamation activities. In 2025, Veren expects to carry out abandonment and reclamation operations that will total approximately $20.0 million. Veren has estimated the net present value (discounted at approximately 3.33% per annum) of its total decommissioning liability (wells and facilities) to be approximately $580.0 million as of December 31, 2024, based on estimated undiscounted and uninflated cash flows of approximately $827.9 million.

On July 30, 2020, the Government of Alberta announced a new liability management program that overhauls and modernizes the previous liability management program, known as the Liability Management Ratio (**"LMR"**) which uses a licensee's ratio of deemed asset value to deemed liability value to determine the risk that the licensee poses to the Orphan Well Association and to determine if a security deposit is required to mitigate that risk. The LMR was replaced by Directive 088: Licensee Life-Cycle Management (**"LLCM"**), which directive was released and became effective on December 1, 2021. Unlike the LMR, which measures two metrics to determine a licensee's risk, the LLCM assesses more than 30 additional metrics, such as the licensee's financial capability, previous closure activity, operational performance and regulatory compliance. Additionally, the new liability framework includes an Inactive Inventory Reduction Program which introduced annual mandatory liability reduction spending targets for each licensee. The new framework also includes the development of a program to address legacy sites that were abandoned, remediated or reclaimed before current requirements were introduced. In September 2022, the AER introduced the Closure Nomination Program as part of LLCM. This program allows for specific, direct stakeholders to nominate inactive sites for abandonment and/or reclamation.

Like the Alberta Government, the Government of Saskatchewan also announced enhancements to its Liability Management Program framework in 2020. This framework includes using licensee-specific data to better reflect the actual deemed asset and liability values, which is expected to improve the accuracy of License Liability Ratings; an Inactive Liability Reduction Program that requires an annual spending target on closure activities; completing the Proportional Risk Transfer model that will assess security deposit requirements for license transfers with a high amount of inactive infrastructure; and addressing regulatory gaps related to new entrants and the acceptable forms of security deposits. To support these new initiatives, the Government of Saskatchewan has enacted *The Financial Security and Site Closure Regulation*, which came into force on January 1, 2023.

Health, Safety and Environment

The health and safety of employees, contractors, visitors and the public, as well as the protection of the environment, is important to Veren. The Corporation endeavors to conduct its operations in a manner that minimizes both adverse environmental effects and consequences of emergency situations by:

- complying with all applicable government regulations and standards;
- operating in a manner consistent with industry codes, practices and guidelines;
- ensuring prompt and effective response and repair to emergency situations and environmental incidents;
- providing training to ensure compliance with Veren's Operations Management System;
- careful planning, good judgment and prudent monitoring of the Corporation's activities;
- communicating openly with all stakeholders regarding our activities; and
- amending Veren's policies and procedures, as may be required from time to time.

Veren believes that it is in material compliance with environmental legislation in the jurisdictions in which it currently operates. Veren's practice is to do all that it reasonably can to ensure that it remains in material compliance with applicable environmental protection legislation. Veren also believes that it is reasonably likely that the trend towards stricter standards in environmental regulation will continue. Veren is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. Veren anticipates increased capital and operating expenditures as a result of increasingly stringent laws relating to the protection of the environment. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, the development or exploration activities, or otherwise adversely affect Veren's financial condition, capital expenditures, results of operations, competitive position or prospects.

DIVIDENDS AND SHARE REPURCHASES

The Corporation has established a dividend policy of paying regular dividends to Shareholders. An objective of the Corporation's dividend policy is to provide Shareholders with relatively stable and predictable dividends. An additional objective is to retain a portion of cash flow to fund ongoing development and optimization projects designed to enhance the sustainability of the Corporation's cash flow. The Corporation currently pays a quarterly dividend, paid on the first business day of each quarter. Dividends are paid to Shareholders of record on the 15th day of the month prior to the payment date.

Additionally, as part of its return of capital framework that targets the return of up to 60% of the Corporation's excess cash flow, the Corporation, has and, in the future, may declare special dividends. No special dividends were declared or paid in 2024.

The amount of cash dividends to be paid on the Common Shares, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including the price of oil and gas, the prevailing economic and competitive environment, results of operations, debt and working capital levels, the taxability of Veren, Veren's ability to raise capital, the amount of capital expenditures and other conditions existing from time to time. There can be no guarantee that Veren will maintain its dividend policy.

Although the Corporation strives to provide Shareholders with stable and predictable cash flows, the percentage of cash flow from operations paid to Shareholders may vary according to several factors, including, fluctuations in resources prices, exchange rates and production rates, reserves growth, the size of development drilling programs and the portion thereof funded from cash flow and the overall level of debt of the Corporation.

The agreements governing the Credit Facilities and Senior Notes provide that distributions to Shareholders and share repurchases are not permitted if the Corporation is in default under the agreements or the payment of such distribution would cause an event of default.

The following table sets forth the amount of cash dividends declared per Common Share by the Corporation for the periods indicated.

			Dividends per Common Share ($)
January 2022	–	December 2022	0.360
January 2023	–	December 2023	0.387
January 2024	–	December 2024	0.460

Normal Course Issuer Bid

On March 9, 2023, Veren commenced the 2023 NCIB to purchase, for cancellation, up to 54,605,659 Common Shares, representing 10% of the Corporation's public float as at February 23, 2023. The 2023 NCIB expired on March 8, 2024. The Corporation had purchased 30,775,500 Common Shares under the 2023 NCIB.

On March 11, 2024, Veren commenced the 2024 NCIB to purchase, for cancellation, up to 61,663,522 Common Shares, representing 10% of the Corporation's public float as at February 29, 2024. The 2024 NCIB is due to expire on March 10, 2025. As of February 12, 2025, the Corporation had purchased 10,429,500 Common Shares under the 2024 NCIB.

The objective of the 2023 NCIB and the 2024 NCIB was to return capital to Shareholders in a way that is accretive to both Shareholders and the Corporation. Purchases of Common Shares under the 2024 NCIB may be made through the facilities of the TSX or the NYSE, alternative trading systems by means of open market transactions, or by such other means as may be permitted by the TSX and applicable securities laws.

MARKET FOR SECURITIES

The outstanding Common Shares are traded on the TSX and the NYSE under the trading symbol "VRN". Prior to May 14, 2024, the outstanding Common Shares were traded on the TSX and the NYSE under the trading symbol "CPG". The following tables set forth the price range and trading volume of the Common Shares as reported by the TSX and NYSE for the periods indicated.

TSX	High ($)	Low ($)	Volume (000's)
2024			
January	9.48	8.51	60,207
February	10.05	8.16	60,812
March	11.12	9.96	78,787
April	12.67	11.00	83,291
May	12.47	11.31	54,431
June	11.86	10.11	53,716
July	11.24	9.91	51,110
August	10.80	9.27	55,203
September	9.50	8.15	78,631
October	9.20	6.95	83,706
November	7.72	6.84	85,755
December	7.43	6.34	91,357
2025			
January	8.11	7.26	78,451
February 1 - 12	7.89	7.02	26,309

NYSE	High (US$)	Low (US$)	Volume (000's)
2024			
January	7.10	6.28	100,653
February	7.41	6.04	120,866
March	8.21	7.34	125,099
April	9.27	8.12	133,784
May	9.13	8.23	76,566
June	8.71	7.34	47,700
July	8.24	7.18	56,159
August	7.81	6.44	56,183
September	7.03	6.04	97,585
October	6.76	4.99	137,555
November	5.55	4.90	139,324
December	5.29	4.40	196,756
2025			
January	5.63	5.02	336,270
February 1 - 12	5.52	4.80	121,357

CONFLICTS OF INTEREST

Circumstances may arise where members of the Board of Directors or officers of the Corporation are directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such Board members or officers will be provided to the Corporation. In accordance with the ABCA, a director or officer who is a party to a material contract or proposed material contract with the Corporation or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Corporation shall disclose to the Corporation the nature and extent of the director's or officer's interest. In addition, a director shall not vote on any resolution to approve a contract of the nature described except in limited circumstances. Management of the Corporation is not aware of any existing or potential material conflicts of interest between the Corporation or a subsidiary of the Corporation and a director or officer of the Corporation or any other subsidiary of the Corporation.

LEGAL PROCEEDINGS

There are no outstanding legal proceedings material to the Corporation to which we are a party or in respect of which any of our properties are subject, nor are any such proceedings known to be contemplated.

RISK FACTORS

Each of the risks described below should be carefully considered, together with all of the other information contained herein, before making an investment decision with respect to our Common Shares. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially and adversely affected, and you could lose all or part of your investment.

Risks Relating to Our Business

Our estimated Proved and Proved plus Probable reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

The Reserves Data and the reserve and recovery information contained in the Veren Reserve Report are only estimates and the actual production and ultimate reserves from our properties may be greater or less than the estimates prepared by McDaniel. Ultimately, actual reserves attributable to our properties will vary from estimates, and those variations may be material. The estimation of reserves is an inherently complex process requiring significant judgment. A number of factors are considered and a number of assumptions are made when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- future commodity prices, production and development costs, royalties and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- success of future development activities;
- marketability of production;
- availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities;
- effects of government regulation; and
- other government levies that may be imposed over the producing life of reserves.

Reserve estimates are based on the relevant factors, assumptions and prices on the date the relevant evaluations were prepared. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change. See "*Special Notes to Reader*". Many of these factors are subject to change and are beyond our control. If these factors, assumptions and prices prove to be inaccurate, actual results may vary materially from reserve estimates and such variations may affect the market price of our Common Shares and return of capital (which, for purposes of this AIF, includes dividends and share repurchases) to Shareholders.

The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems.

Our business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and rail loading facilities and railcars. Canadian federal and provincial, as well as U.S. federal, state and local, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, changes in supply and demand and changes in pipeline ownership or operation could adversely affect our ability to produce or market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which may affect the market price of our Common Shares and reduce our return of capital to our Shareholders.

Our future performance depends on our ability to acquire additional natural gas and oil reserves that are economically recoverable.

If we are unable to acquire additional reserves, the value of our Common Shares and our return of capital to Shareholders may decline. We add to our oil and natural gas reserves primarily through development, exploitation and acquisitions including those with large resource potential. As a result, future oil and natural gas reserves are highly dependent on our success in exploiting existing properties and acquiring additional reserves. Operations may be curtailed, delayed or canceled as a result of lack of adequate capital and other factors, such as lack of availability of rigs and other equipment, title problems, weather, compliance with governmental regulations or price controls, mechanical difficulties, or unusual or unexpected formations, pressures and/or work interruptions. In addition, the costs of exploration and development may materially exceed our internal estimates. We cannot guarantee that we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserve additions, our reserves will deplete and, as a consequence, either production from, or the average reserve life of, our properties may decline. Either decline may result in a reduction in the value of our Common Shares and in a reduction in cash available for return of capital to Shareholders.

The properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the acquired properties or obtain protection from sellers against such liabilities.

The properties we acquire may not produce as expected, may be in an unexpected condition and we may be subject to increased costs and liabilities, including environmental liabilities. Although we review properties prior to acquisition in a manner consistent with industry practices, such reviews are not always capable of identifying all potential adverse conditions. Furthermore, we may not be able to subject the preparation of reserve estimates for acquired properties to the same internal controls we have for the preparation of reserve estimates for our existing properties. Generally, it is not feasible to review in depth every individual property involved in each acquisition. We focus our review efforts on the higher-value properties or properties with known adverse conditions and will sample the remainder. However, even a detailed review of records and properties and preparation of reserve reports in accordance with our internal controls may not necessarily reveal existing or potential problems or permit us to become sufficiently familiar with the properties to fully assess their condition, any deficiencies, and development potential.

Failure to realize anticipated benefits of prior acquisitions and dispositions may have a material adverse effect on our business.

The Corporation has completed a number of acquisitions and dispositions in order to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits, including, among other things, potential cost savings. In order to achieve the benefits of these and future acquisitions, the Corporation is dependent upon its ability to successfully consolidate functions and integrate operations, procedures and personnel in a timely and efficient manner and to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with those of the Corporation. The integration of acquired assets and operations requires the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the disruption of ongoing business and customer relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of such prior acquisitions. Dispositions may fail to provide anticipated benefits as the deployment of capital received from any such dispositions will be subject to the risks the Corporation faces. Such capital may fail to deliver a return commensurate or greater than the return formerly garnered from the disposed assets.

Increases in costs could adversely affect our business, financial condition and results of operations.

An increase in costs could have a material adverse effect on our results of operations and financial condition and, therefore, could reduce our ability to pay down debt, reduce dividends to Shareholders as well as affect the market price of the Common Shares.

Current and future inflationary effects may be driven by, among other things, supply chain disruptions and governmental stimulus or fiscal policies, and geopolitical instability, including the ongoing conflict between Ukraine and Russia and the conflict in the Middle East. Increases in inflation could increase our costs of labor and other costs related to our business, which could have an adverse impact on our business, financial position, results of operations and cash flows.

Higher operating and capital costs for our underlying properties will directly decrease the amount of cash flow received by the Corporation and, therefore, may reduce return of capital to our Shareholders.

The conflicts in Ukraine and the Middle East and related price volatility and geopolitical instability could negatively impact our business.

Conflicts and other events causing geopolitical instability, have caused, and could intensify, volatility in natural gas, oil and NGL prices, and the extent and duration of the military actions, sanctions and resulting market disruptions could be significant and could potentially have a substantial negative impact on the global economy and our business for an unknown period of time. There is evidence that volatility in crude oil prices is partially due to the impact of geopolitical instability, including the conflict between Russia and Ukraine and in the Middle East, on the global commodity and financial markets, and in response to economic and trade sanctions that certain countries have imposed on Russia. Any such volatility and disruptions may also magnify the impact of other risks described in this "Risk Factors" section.

The operation of a portion of our properties is largely dependent on the ability of third-party operators.

Some of our properties are not operated by us and, therefore, results of operations may be adversely affected by the failure of third-party operators, which could affect the market price of our Common Shares and return of capital to Shareholders.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of those properties. At December 31, 2024, approximately 4% of our daily production was from properties operated by third parties. To the extent a third-party operator fails to perform its functions efficiently or becomes insolvent, our revenue may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

Further, the operating agreements which govern the properties not operated by us typically require the operator to conduct operations in a good and "workmanlike" manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operated working interest owners for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or willful misconduct.

Delays in business operations could adversely affect our income and financial condition.

Delays in business operations could adversely affect return of capital to Shareholders, our income, our financial condition and the market price of our Common Shares. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- restrictions due to limited pipeline, railcar, trucking or refinery capacity;
- extreme weather events, including severe cold, wildfires and floods, which may damage or destroy infrastructure;
- droughts, which may impact the availability and usage of water;
- blowouts or other accidents;
- public health crises, epidemics or pandemics, including the effects of, and response to, COVID-19;
- blockades and social unrest;
- accounting delays;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties;
- the establishment by the operator of reserves for these expenses; or
- delays in receiving government approvals and licenses.

Any of these or other delays in our business operations could reduce our income, the amount of cash available for return of capital to Shareholders in a given period, our financial condition and could expose us to additional third party credit risks.

Failure of third parties to meet their contractual obligations to us may have a material adverse effect on our financial condition.

Although the Corporation monitors the credit worthiness of third parties it contracts with and manages its exposures through a formal Risk Management and Counterparty Credit Policy, there can be no assurance that the Corporation will not experience a loss for non-performance by any counterparty with whom it has a commercial relationship. Such events may have material adverse consequences on the business of the Corporation and may limit the timing or amount of return of capital to Shareholders and could affect the market price of our Common Shares.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, ability to return capital to shareholders, results of operations, cash flows and business prospects.

We may, from time to time, finance a significant portion of our operations through debt. Our indebtedness may limit the timing or amount of capital returns to Shareholders and could affect the market price of our Common Shares and our return of capital to Shareholders.

The payments of interest and principal, and other costs, expenses and disbursements to our lenders reduces amounts available for return to Shareholders. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the cash flow required to be applied to the debt before payment of any amounts to the Shareholders. The agreements governing our long-term debt provide that, if we are in default or fail to comply with certain covenants, we must repay the indebtedness at an accelerated rate, and the ability to return capital to Shareholders may be restricted. Significant reductions to cash flow or increases in drawn amounts under the Credit Facilities may result in the Corporation breaching its debt covenants under the agreements governing its debt. If a breach occurs, there is a risk that the Corporation may not be able to negotiate covenant relief with one or more of its debt counterparties. Failure to comply with debt covenants or negotiate relief may result in its indebtedness under the Credit Facilities or Senior Notes becoming immediately due and payable, which may have a material adverse effect on the Corporation’s operations and financial condition.

Increased costs of capital could adversely affect our business.

Our business and operating results could be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in our credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows and place us at a competitive disadvantage. Disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could have a material adverse effect on the Corporation's operations and financial condition.

Our existing Credit Facilities and any replacement credit facilities may not provide sufficient liquidity.

Our current Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our existing Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. The interest charged on our Credit Facilities is calculated based on a sliding scale ratio of the Corporation's senior debt to adjusted EBITDA ratio. Repayment of all outstanding amounts under the Credit Facilities may be demanded on relatively short notice if an event of default occurs and is continuing. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business and return of capital to Shareholders may be materially reduced.

Dividends on the Corporation's Common Shares and Common Share repurchases are variable.

Dividends may be reduced or eliminated in the sole discretion of the Board of Directors. For example, dividends may be reduced or eliminated during periods in which we make capital expenditures or debt repayments using cash flow, which could also affect the market price of our Common Shares. To the extent that we use cash flow to finance acquisitions, development costs and other significant expenditures, the net cash flow the Corporation receives that is available for dividends to Shareholders, or to repurchase Common Shares, will be reduced. Furthermore, the availability of net cash flow is dependent upon commodity prices which are variable. Hence, the timing and amount of capital expenditures and the variability of commodity prices, may affect the amount of net cash flow received by the Corporation and, as a consequence, the amount of cash available to distribute to Shareholders or to repurchase Common Shares. Therefore, dividends or share repurchases may be reduced, or even eliminated, at times when significant capital or other expenditures are made, or when commodity prices vary.

The Board of Directors has the discretion to determine the extent to which cash flow from Veren will be allocated to the payment of debt service charges as well as the repayment of outstanding debt, including under the Credit Facilities and Senior Notes. As a consequence, the amount of funds used to pay debt service charges or reduce debt will reduce the amount of cash available for dividends to Shareholders or to repurchase Common Shares during those periods in which funds are so retained..

We have been historically reliant on external sources of capital, which may dilute Shareholders' ownership interests.

There may be future dilution to our Shareholders. One of our objectives is to continually add to our reserves through development, and where warranted, through acquisitions. Since we pay a dividend, our success in growth from development and acquisitions may, in part, depend on our ability to raise capital from time to time by selling additional Common Shares. Shareholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Common Shares issued to develop or acquire assets. Shareholders may also suffer dilution in connection with future issuances of Common Shares to effect acquisitions.

Indigenous claims could have an adverse effect on us and our operations.

The economic impact on us of claims of indigenous title or rights is unknown. Indigenous people have claimed indigenous title and rights to a substantial portion of western Canada. We are unable to assess the effect, if any, that any such claim would have on our business and operations. Indigenous claims could impact our ability to obtain regulatory and environmental permits from government that are needed to develop our assets. Protests that affect transportation and other infrastructure in Canada, may have a negative impact on the Corporation's ability to sell its products.

Hedging limits participation in commodity price increases and increases counterparty credit risk exposure.

We periodically enter into hedging activities with respect to a portion of our production to manage our exposure to oil and gas price volatility. To the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from fully realizing the benefits of commodity price increases above the prices established by our hedging contracts. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which the contract counterparties fail to perform under the contracts.

We may incur losses as a result of title defects in the properties in which we invest.

Unforeseen title defects may result in a loss of entitlement to production and reserves. Although we conduct title reviews in accordance with industry practice prior to any purchase of resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat our title to the purchased assets. If such a defect were to occur, our entitlement to the production from such purchased assets could be jeopardized and, as a result, return of capital to Shareholders may be reduced.

Our information assets and critical infrastructure may be subject to cyber security risks.

The Corporation is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Corporation's information technology systems by third parties or insiders. From time to time we experience cyber-attacks and other security incidents of varying degrees (such as phishing attempts), none of which have had a material adverse effect on our business or operations to date. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Veren relies heavily on information technology, such as computer hardware and software systems, in order to properly operate its business. In the event the Corporation is 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 addition, information systems could be damaged or interrupted by natural disasters, *force majeure* events, telecommunications failures, power loss, acts of war or terrorism, computer viruses, malicious code, physical or electronic security breaches, intentional or inadvertent user misuse or error, or similar events or disruptions. Any of these or other events could cause interruptions, delays, loss of critical or sensitive data or similar effects, which could have a material adverse impact on the protection of intellectual property, and confidential and proprietary information, and on Veren's business, financial condition, results of operations and cash flows.

Cybersecurity and data protection laws and regulations continue to evolve, and are increasingly demanding, both in the U.S. and Canada, which adds compliance complexity and may increase the Corporation's costs of compliance and expose it to reputational damage or litigation, monetary damages, regulatory enforcement actions, or fines.

We depend upon our management team and our operations require us to attract and retain experienced technical personnel.

Shareholders are entirely dependent on our management with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves and the management and administration of all matters relating to our oil and natural gas properties. The loss of the services of one or more key individuals of our management team could have a detrimental effect on the Corporation.

Pandemics could adversely affect the Corporation's financial condition, operations and results from operations.

A pandemic and the actions taken in response, could result in a similar contraction in the global economy as experienced in response to COVID-19. Another pandemic could cause periods of unprecedented disruption in the oil and gas industry and negatively impact the demand for, and pricing of, energy products, including crude oil, NGLs and natural gas produced by the Corporation. A consequence of this disruption is that the oil and gas industry could again experience a period of market contraction. Furthermore, the oil and gas industry could experience an increased risk of counterparty bankruptcy and insolvency.

In response to a pandemic, the Corporation may need to implement additional health and safety protocols within its Calgary office and field operations and may be required to make adjustments to its health and safety protocols.

We operate only in western Canada and expansion outside of these areas may increase our risk exposure.

If we expand our operations beyond oil and natural gas production in western Canada, we may face new challenges and risks. If we were to be unsuccessful in managing these challenges and risks, our results of operations and financial condition could be adversely affected, which could affect the market price of our Common Shares and return of capital to Shareholders.

Our operations and expertise are currently deployed on conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. In addition, we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present challenges and risks that we have not faced in the past. If we do not manage these challenges and risks successfully, our results of operations and financial condition could be adversely affected.

We may be the subject of litigation.

From time to time, the Corporation may be the subject of litigation. Claims under such litigation may be material. The types of claims the Corporation may face include, without limitation, claims for breach of contract, environmental damage, negligence, product liability, tax, patent infringement and employment matters. The outcome of any such litigation is not certain, but may materially impact Veren's financial condition or results of operations. Veren may also be subject to adverse publicity related to such claims, regardless of whether Veren is ultimately found responsible. In addition, the Corporation may be required to incur significant expenses or devote significant resources defending any such litigation.

The Corporation relies on surface and groundwater licenses, which, if rescinded or the conditions of which are amended, could disrupt its business and have a material adverse effect on its business, financial condition, results of operations and prospects.

The Corporation relies on access to both surface and groundwater, which is obtained under government licenses, to provide the substantial quantities of water required for certain of its operations. The licenses to withdraw water may be suspended or rescinded and additional conditions may be added to these licenses. Further, the Corporation may have to pay increased fees for the use of water in the future and any such fees may be uneconomic. Finally, new projects or the expansion of existing projects may be dependent on securing licenses for additional water withdrawal, and these licenses may not be available or may be granted on terms not favorable to the Corporation, or at all, and such additional water may not be available to divert under such licenses. Any prolonged droughts in our operating areas could result in the Corporation's surface and groundwater licenses being subject to additional conditions, suspension or rescission. The Corporation's inability to secure surface and groundwater licenses in the future and any amendment to or suspension or rescission of its current licenses may disrupt its business and have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Wildfire Risk

Wildfires may restrict the Corporation's ability to access and operate its properties and cause operational difficulties, including damage to equipment and infrastructure. Wildfires also increase the risk of personnel injury as a result of dangerous working conditions. Certain of the Corporation's assets are located near forests and a wildfire may lead to significant downtime and/or damage to the Corporation's assets or cause disruptions to the production and transport of its products or the delivery of goods and services in its supply chain.

Restrictions on operational activities intended to protect certain species of wildlife may adversely affect the Corporation's ability to conduct drilling and other operational activities in some of the areas where it operates.

Oil, condensate and other NGLs and natural gas operations in the Corporation's operating areas can be adversely affected by seasonal or permanent restrictions on construction, drilling and well completions activities designed to protect various wildlife. Seasonal restrictions may limit the Corporation's ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling and completions activities are allowed. These constraints and the resulting shortages or high costs could delay the Corporation's operations and materially increase the Corporation's operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit development in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species as threatened or endangered in areas where the Corporation operates could cause the Corporation to incur increased costs arising from species protection measures or could result in limitations on the Corporation's exploration and production activities that could have an adverse impact on the Corporation's ability to develop and produce its reserves.

Risks Relating to the Oil and Gas Industry

Oil and natural gas prices fluctuate widely, and low prices for an extended period would likely have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for oil and natural gas. Lower commodity prices may reduce the amount of oil and natural gas that we can produce economically. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results and could result in impairment charges.

Prices for oil and natural gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to, the following:

- the levels and location of oil and natural gas supply and demand and expectations regarding supply and demand, both domestically and abroad;
- the level of consumer product demand;
- extreme weather events, such as severe cold, wildfires and floods;
- political conditions, social unrest, sanctions, hostilities or war in, or relating to, oil and natural gas producing regions, including the Middle East, Africa, Eastern Europe (including the conflict between Ukraine and Russia) and South America;
- the ability of the members of the Organization of Petroleum Exporting Countries and other exporting nations to agree to and maintain oil price and production controls;
- the price level and quantity of foreign imports;
- actions of governmental authorities, including the imposition of tariffs on our products;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for oil and natural gas;
- blockades of transportation infrastructure and civil unrest;
- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- conservation and environmental protection efforts;
- the price, availability and acceptance of alternative energy sources;
- technological advances affecting energy usage and consumption and energy supply;
- speculation by investors in oil and natural gas;
- public health crises, epidemics or pandemics;
- weather conditions;
- variations between product prices at sales points and applicable index prices; and
- overall domestic and worldwide economic conditions, including the value of the U.S. dollar relative to Canadian and other major currencies.

These factors and the volatile nature of the energy markets make it extremely difficult to predict with any certainty the future prices of crude oil and natural gas. If crude oil and natural gas prices remain significantly depressed for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital, meet our financial obligations or provide return of capital to shareholders through dividends or share repurchases.

Variations in interest rates, foreign exchange rates, and inflation could adversely affect our financial condition.

There is a risk that interest rates could increase in response to inflation in Canada and the United States. An increase in interest rates could result in a significant increase in the amount we pay to service debt, while rising inflation could cause us to incur additional expense and, either or both, could have an adverse effect on our financial condition, results of operations and future growth, potentially resulting in a decrease in the return of capital to Shareholders and/or the market price of the Common Shares.

Fluctuations in foreign currency exchange rates could adversely affect our business, and could affect the market price of our Common Shares and return of capital to Shareholders. The price that we receive for a majority of our oil and natural gas is based on U.S. dollar denominated benchmarks and, therefore, the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the U.S. dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given U.S. dollar price. Each of these situations may negatively impact future dividends and the future value of the Corporation's reserves as determined by independent evaluators. We could be subject to unfavorable exchange rate changes to the extent of our investment in U.S. subsidiaries and to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

Competition in the oil and gas industry is intense, which may adversely affect our ability to compete.

The oil and natural gas industry is highly competitive. We compete for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than we do. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a worldwide basis. As a result of these complementary activities, some of our competitors may have greater and more diverse competitive resources to draw on than we do. Given the highly competitive nature of the oil and natural gas industry, this could adversely affect the market price of our Common Shares and return of capital to Shareholders.

Risks associated with the production, gathering, transportation and sale of oil and natural gas could adversely affect net income and cash flows. We may not be insured against all of the operating risks to which our business is exposed.

The industry in which we operate exposes us to potential liabilities that may not be covered by insurance. Our operations are subject to all of the risks associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells, and the production and transportation of oil and natural gas. These risks include encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, equipment failures and other accidents, cratering, sour gas releases, uncontrollable flows of oil, natural gas or well fluids, adverse weather conditions, pollution, other environmental risks, fires, spills and explosions. A number of these risks could result in personal injury, loss of life, or environmental and other damage to our property or the property of others and reputational loss. We cannot fully protect against all of these risks, nor are all of these risks insurable. We may become liable for damages arising from these events against which we cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Any costs incurred to repair these damages or pay these liabilities would reduce funds available for payment of dividends to Shareholders. Additionally, the insurance market changes over time and, in the future, we may not be able to purchase insurance for all of the risks that we are currently able to insure against.

We are subject to complex laws that can affect the cost, manner or feasibility of doing business.

Veren is subject to extensive and complex regulations and laws enforced by various regulatory agencies. These regulatory agencies include, in Canada, the AER, the Alberta EPA, the British Columbia Energy Regulator, the British Columbia Ministry of Environment and Climate Change Strategy, the SMER, Saskatchewan Ministry of Environment, the Canadian Energy Regulator, Environment and Climate Change Canada, Health Canada and Transport Canada. Additionally, the development or implementation of changes to land use activities, such as regional or subregional planning, may affect how we are able to use certain lands for oil and gas development. Veren is also subject to regulation by other federal, provincial, state and local agencies. Regulations affect almost every aspect of Veren's business and limit its ability to make and implement independent management decisions, including about business combinations, disposing of operating assets and engaging in transactions between Veren and its affiliates.

Under these laws and regulations, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws and regulations could change in ways that could substantially increase our costs. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our financial condition and results of operations.

Regulations and laws are subject to ongoing policy initiatives, and Veren cannot predict the future course of regulations or legislation and their respective ultimate effects. Such changes could materially impact Veren's business, financial position and results of operations.

For further discussion about the effect of environmental laws and regulations, see below "*Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations*".

Our operations may incur substantial costs and liabilities to comply with environmental laws and regulations.

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that Veren may be in non-compliance with an environmental law, regulation, permit, license or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose Veren to fines or penalties, suspension or revocation of regulatory permits, third party liabilities or to the requirement to remediate or carry out other actions, the costs of which could be material. The operational hazards associated with possible blowouts, accidents, oil spills, gas leaks, fires, explosions or other damage to a well, pipeline or facility may require Veren to incur costs and delays to undertake corrective actions, and could result in penalties and fines and suspension or revocation of regulatory approvals or environmental or other damage for which Veren could be liable. Oil and gas operations are also subject to specific operational risks which may have a material operational and financial impact on Veren should they occur, such as drilling into unexpected formations or unexpected pressures, premature decline of reservoirs and water invasion into producing formations.

Veren may also be subject to associated liabilities resulting from lawsuits alleging property damage or personal injury brought by private litigants related to the operation of Veren's facilities or the land on which such facilities are located, regardless of whether Veren leases or owns the facility, and regardless of whether such environmental conditions were created by Veren, a prior owner or tenant, a third party or a neighbouring facility whose operations may have affected Veren's facility or land. Such liabilities could have a material adverse effect on Veren's business, financial position, operations, assets or future prospects.

Veren also faces uncertainties related to future environmental laws and regulations affecting its business and operations. Existing environmental laws and regulations may be revised or interpreted more strictly, and new laws or regulations may be adopted or become applicable to Veren, which may result in increased compliance costs or additional operating restrictions, each of which could reduce Veren's earnings and adversely affect Veren's business, financial position, operations, assets or future prospects. For example, if the Corporation did not qualify in 2024 for an exemption under the TIERS and OBPS programs in Alberta and Saskatchewan, respectively, the additional carbon compliance costs to the Corporation in Canada would have been, approximately, $72.0 million in 2024, which amount is calculated based on Scope 1 fuel combustion and flaring emissions at the applicable 2024 carbon pricing rate.

Compliance with environmental laws and regulations could materially increase our costs. We may incur substantial capital and operating costs to comply with increasingly complex laws covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with future federal GHG emissions reduction requirements or other GHG emissions regulations. See below "*Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for oil and gas that we produce*".

Although we record a provision in our consolidated financial statements relating to our estimated future abandonment and reclamation obligations, we cannot guarantee that we will be able to satisfy our actual future abandonment and reclamation obligations. In addition, estimates of the costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. Although the Corporation maintains insurance consistent with prudent industry practice, we are not fully insured against certain environmental risks, including the impacts of climate change, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms.

Accordingly, our properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. It is also possible that changing regulatory requirements or emerging jurisprudence could render such insurance of less benefit to Veren. Any site remediation, reclamation or abandonment costs actually incurred in the ordinary course of business in a specific period will be funded out of our reclamation budget and, if required, out of cash flow and, therefore, will reduce the amounts available for return of capital to Shareholders. Should we be unable to fully fund the cost of remedying an environmental problem, we might be required to suspend or terminate certain operations or enter into interim compliance measures pending completion of the required remedy.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for oil and gas that we produce.

Complying with climate change legislation and regulations has increased operating costs as we pay fuel charges imposed by such legislation and have undertaken initiatives to reduce GHG emissions. Additionally, complying with methane reduction regulations applicable to our business requires Veren to incur additional operating costs in order to achieve compliance.

Changes to federal legislation, as well as legislation in Alberta and Saskatchewan, require the restriction or reduction of GHG emissions or emissions intensity from our current and future operations and facilities, which may lead to increased operational costs associated with emission reductions, payments to technology or decarbonization funds, payments of carbon levies, the purchase and retirement of emission reductions, allowances or offset credits, or a combination of such actions. The required GHG reductions may not be technically or economically feasible for our operations and the failure to meet such emission reduction or emission intensity reduction requirements or other compliance mechanisms may materially adversely affect our business and result in fines, penalties and the suspension of some operations. Furthermore, equipment from suppliers which can meet future emission standards may not be available on an economic basis and other compliance methods of reducing emissions or emission intensity to levels required in the future may significantly increase our operating costs or reduce output. Emission reductions, allowances or offset credits may not be available on an economic basis. Additionally, changes in technology could decrease the demand for our products.

The current state of development of ongoing international climate initiatives and any related domestic actions makes it difficult to assess the timing or effect on our operations or to predict with certainty the future costs that we may incur in order to comply with future international treaties or regulations. Moreover, many experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in precipitation and extreme weather events, including severe cold, wildfires, droughts and floods, which can result in damage to or destruction of infrastructure, facilities and equipment. In addition, warmer winters in some regions as a result of climate change could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are realized due to climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable.

We may be unable to meet emissions targets.

We have set internal emissions reduction targets with respect to GHG emissions. There are substantial costs and operational changes required to meet such targets, and as such, we may be unable to finance the required changes to meet our emissions targets due to lack of capital for a variety of reasons, many of which are beyond our control. Additionally, we may be unable to adequately alter our operations in such a way as to meet our emissions targets by the stated dates or at all.

Changes in market-based factors may adversely affect the trading price of the Common Shares.

The market price of our Common Shares is sensitive to a variety of market-based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates and the comparability of the Common Shares to other securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Federal, provincial and local legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Some of Veren's operations use hydraulic fracturing, which involves the high-pressure injection of fluids and sand down a well to fracture the reservoir and thereby stimulate the increased flow of oil or gas into the well bore. Hydraulic fracturing has been the subject of greater regulatory and public scrutiny and regulation in certain jurisdictions of the world, including some of the areas in which Veren operates. In a limited number of areas, hydraulic fracturing has been banned pending public and scientific reviews or is subject to moratoria while regulators study the practice. Additionally, hydraulic fracturing has been found to induce seismicity, and the AER has developed monitoring and reporting requirements that companies must follow in certain areas of Alberta, and in certain cases, the AER may require that operations resulting in increased seismic activity be suspended and not resumed without AER approval. We may be required to expend additional costs to comply with future regulatory requirements with respect to hydraulic fracturing or, in the future, be unable to carry out hydraulic fracturing operations, thereby lessening the volume of oil and gas we could otherwise produce and this could have a material operational and financial impact on Veren and adversely affect the market price of our Common Shares and dividends to Shareholders.

Income tax laws, tariffs, trade restrictions or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders.

Changes in tax and other laws may adversely affect the trading price of our Common Shares and return of capital to Shareholders. Tax authorities having jurisdiction over the Corporation or the Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of Shareholders.

The oil and gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of, and tariffs or trade restrictions on, oil and natural gas by agreements among the governments of Canada, the provinces, the United States, and the various states, all of which should be carefully considered by investors in the oil and gas industry. On February 1, 2025, the U.S. government announced the proposed implementation of a 25% tariff on imports from Canada into the U.S. On February 2, 2025, the Canadian government announced proposed retaliatory tariffs on certain goods imported from the U.S. into Canada. On February 3, 2025, the tariffs were paused until March 4, 2025. On February 10, 2025, the U.S. government announced the proposed implementation of 25% tariffs on steel and aluminum imports from Canada. On the same day, Canada responded by announcing its intent to implement similar tariffs against U.S. steel and aluminum imports to Canada. The timing and implementation of such tariffs is uncertain. To the extent such tariffs impact the marketing of oil and natural gas by Veren in the United States, there could be a material adverse impact to Veren. All of such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition or results of operations or prospects and our ability to return capital to Shareholders.

Our business and financial performance may be adversely affected by subsequent unavailability and unfavorable terms of water licenses.

Veren utilizes fresh water in certain operations, including hydraulic fracturing operations, which water is obtained under licenses issued within each respective jurisdiction's regulations. If water use fees increase or a change under these licenses 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 licenses to withdraw water will not be suspended or rescinded, that additional conditions will not be added to these licenses or that the licenses or water licensed will be available. There is no assurance that if we require licenses or amendments to existing licenses, that these licenses or amendments will be granted on favorable terms. This may adversely affect our business, including the ability to operate our assets and execute development plans.

The Corporation's risk and/or cost of borrowing may be adversely affected by the uncertainty resulting from the Orphan Well Association v Grant Thornton Ltd. court decision.

On January 31, 2019, the Supreme Court of Canada released its decision in *Orphan Well Association v Grant Thornton Ltd.*(the "**Redwater decision**") overturning earlier decisions of the Alberta courts to hold that receivers and trustees can no longer avoid the AER legislated authority to impose abandonment orders against licensees, or require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. As a result, any financial resources of a bankrupt licensee in Alberta may first be used to satisfy outstanding abandonment and reclamation obligations in respect of its unproductive assets. Remaining amounts, if any, will then satisfy the claims of secured creditors in accordance with the *Bankruptcy and Insolvency Act*. As a result of the Redwater decision, the provincial regulation of environmental liabilities and associated decommissioning liability in the oil and gas industry is undergoing changes. On January 1, 2023, SMER changed how it assesses the financial ability of operators/licensees to meet their abandonment, reclamation and other regulatory obligations and on December 1, 2021, the AER brought into force the new LLCM. The impact of any such regulatory measures by a provincial or federal government on the Corporation is uncertain at this time.

Additionally, some issuers have been required by lenders to include covenants with respect to the asset recovery obligations in the agreements that govern their borrowings (including credit facilities and other debt obligations) following the Redwater decision. To date, the Corporation has not been required by its lenders to include such provisions, however, there can be no certainty that the Corporation's lenders will not require such or other covenants and contractual terms, which in turn could cause the Corporation's risk and/or cost of borrowing to increase, possibly materially.

Safety requirements involving rail transportation may adversely affect us and our Shareholders.

In response to train derailments occurring in the United States and Canada in 2013, U.S. and Canadian regulators have implemented additional rules to address the safety risks of transporting crude oil by rail.

In Canada, amendments have been made to the *Transportation of Dangerous Goods Regulations* which adopt a new class of tank car for flammable liquid dangerous goods service, and which require all new rail tank cars destined for flammable liquid service to be built to the new specifications. Certain older tank cars used to transport crude oil have been phased out. Further, shippers of crude oil by rail now must have in place an Emergency Response Assistance Plan approved by the Minister of Transportation in order to be able to provide assistance to responders in the event of an accident. Other amendments require the consigner of a shipment of crude oil by rail to properly classify the crude oil and to certify that the classification is correct. Additionally, Transport Canada has introduced requirements for railway companies to reduce the speed of trains carrying dangerous goods such as crude oil and to implement various other safe operating practices.

In the United States, the Department of Transportation has adopted regulations for the transportation of flammable liquids, which align with the standards adopted by Canada. Among other matters, the regulations require enhanced braking systems on trains transporting flammable liquids, restricts operating speeds, requires a risk assessment-based routing analysis, and mandates procedures for more accurate classification of crude oil.

These regulations and the adoption of any other regulations that impact the testing or rail transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout Canada and the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

Royalty changes may adversely affect us.

Royalty frameworks, including rates and available incentive programs, may be reviewed and amended from time to time by the applicable federal, provincial, state or other governmental bodies or agencies having jurisdiction. In addition, the royalty rates applicable to the Corporation’s production of hydrocarbons may be impacted by changes in market prices for hydrocarbons, production volumes, and capital and operating costs. An increase in royalty rates would reduce the Corporation's cash flow and earnings, and could make future capital investments, or the Corporation's operations, less economic.

We are affected by seasonal weather patterns.

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities, provincial and state transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors, unexpected weather patterns, extended periods of extreme temperatures (hot and cold). wildfires, floods and droughts may lead to declines in exploration and production activity and corresponding declines in the demand for crude oil and natural gas.

We may be adversely affected by extreme weather events.

Extreme weather events are an unpredictable risk. Wildfires can be caused by lightning, high temperatures, or by human activity and can spread because of wind and are otherwise encouraged by hot dry conditions. Floods can be caused by a high level of precipitation in a short period of time. Severe cold can cause water to freeze and expand leading to a chance that pipes can burst and valves may break. Wildfires, floods and severe cold can cause damage to or destroy infrastructure including roads, rail lines, and power transmission lines, cause damage to facilities and equipment, cause operational difficulties and access restrictions, lead to reduced operations or a cessation of operations in affected areas, and can cause supply chain disruptions affecting both our ability to market oil and gas and our ability to obtain goods and services required for our operations. Drought can lessen the availability of water required to conduct our operations. Extreme weather events could adversely affect our business and operations, however, due to the unpredictable nature of extreme weather events, it is not possible to determine how or to what extent our business or operations may be affected.

We may be subject to environmental non-governmental organization or anti-greenwashing legal challenges.

Environmental non-governmental organizations have become more aggressive in pursuing legal challenges to oil and gas companies, drilling and pipeline projects. In turn, this could result in increased costs and additional operating restrictions or delays as well as the risks under "*Risks Relating to Our Business - We may be Subject to Litigation*."

We continue to monitor the development of applicable anti-greenwashing laws and regulations as well as climate-related litigation and regulatory enforcement actions related to greenwashing, including certain recent amendments to the Competitions Act (Canada), which came into force on June 20, 2024. These amendments introduced new and uncertain substantiation standards for environmental claims and which provides third parties with a private right of action. These provisions are in addition to the pre-existing provisions of the Competition Act (Canada) that prohibit the making of claims that are materially false or misleading. These laws, regulations and actions may heighten or increase our litigation and regulatory compliance risks. "Greenwashing" generally refers to the practice of conveying false or misleading information about an organization's products or services or operations to suggest that the organization is doing more to protect the environment than it is.

Investor sentiment towards fossil fuel development may not align with our business.

Investor sentiment towards fossil fuel development has been affected by a number of factors, including public perception, climate change, environmental impacts of operations, environmental damage resulting from accidental releases, responsibility for orphaned wells and Indigenous rights. As a result of these and other concerns, some institutional, retail and governmental investors have announced that they will no longer fund or invest in oil and natural gas, or are reducing their investments in the same. Some institutional investors are also requesting that issuers develop and implement robust social, environmental and governance policies and practices, which may be more stringent than those which Veren already has in place. Changing investor sentiment can make capital harder to access or more expensive, and may also have an effect on the value of our assets. It is not expected that changing investor sentiment will affect our operations in a manner materially different than they would affect other oil and gas entities of similar size.

Certain Risks for United States and other non-resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited.

Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all or a substantial portion of our assets and the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States.

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties), however, we also follow the United States practice of separately reporting these volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves, whereas, the SEC rules require that a trailing 12-month average price, calculated as the unweighted arithmetic average of the first day of each month within the 12-month period to the end of the reporting period, and uninflated (constant) costs be utilized. The SEC permits, but does not require, the disclosure of reserves based on forecast prices and costs.

Reserve information contained herein include estimates of Proved and Proved plus Probable reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only Proved reserves. The SEC permits, but does not require, the inclusion of estimates of Probable reserves in filings made with it by United States oil and gas companies. The SEC definitions of Proved reserves and Probable reserves are different than those in NI 51-101. As a consequence of the foregoing, our reserve estimates and production volumes in this AIF may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

Shareholders who are non-residents of Canada may be subject to additional taxation.

The Tax Act imposes a withholding tax at the rate of 25% on dividends paid by us to Shareholders who are non-residents of Canada, unless the rate is reduced under the provisions of a tax treaty between Canada and the non-resident Shareholder's jurisdiction of residence. These withholding tax rates may change from time to time. Where the non-resident Shareholder is a United States resident entitled to benefits under the Canada-United States Income Tax Convention, 1980 and is the beneficial owner of the dividend, the rate of Canadian withholding tax applicable to dividends is generally reduced to 15%. Shareholders who are non-residents of Canada are encouraged to consult with their tax advisors for more information concerning additional taxation that may be applicable to them.

Shareholders who are non-residents of Canada may be subject to foreign exchange risk.

Our dividends are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to their home currency.

AUDIT COMMITTEE

General

The Corporation has established an Audit Committee (the "**Audit Committee**") comprised of five members: Mike Jackson (Chair), Corey Bieber, Jodi J. Jenson Labrie, François Langlois and Myron M. Stadnyk each of whom is considered "independent" and "financially literate" within the meaning of National Instrument 52-110 – Audit Committees and "independent" under Rule 10A-3 of the U.S. Securities Exchange Act of 1934, as amended (the "**Exchange Act**"), and Rule 303A.07 of the NYSE Listed Company Manual.

Mandate of the Audit Committee

The mandate of the Audit Committee is to assist the Board of Directors in its oversight of the integrity of the financial and related information of the Corporation and its subsidiaries and related entities, including the consolidated financial statements, internal controls and procedures for financial reporting and the processes for monitoring compliance with legal and regulatory requirements. In doing so, the Audit Committee oversees the audit efforts of our external auditors and, in that regard, is empowered to take such actions as it may deem necessary to satisfy itself that our external auditors are independent of us. It is the objective of the Audit Committee to have direct, open and frank communications throughout the year with management, other Committee chairs, the external auditors, and other key committee advisors or the Corporation's staff members, as applicable.

The Audit Committee's function is oversight. Management of the Corporation is responsible for the preparation, presentation and integrity of the consolidated financial statements of the Corporation. Management is responsible for maintaining appropriate accounting and financial reporting principles and policies as well as internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. Additionally, the Audit Committee reviews the cyber risks facing the Corporation and any related policies for managing cyber risk, as well as the Corporation's enterprise risk management policy, processes and framework and the assessment of enterprise risk management effectiveness by internal audit.

While the Audit Committee has the responsibilities and powers set forth above, it is not the duty of the Audit Committee to plan or conduct audits or to determine whether the consolidated financial statements of the Corporation are complete and accurate and are in accordance with generally accepted accounting principles. This is the responsibility of management and the external auditors, on whom the members of the Committee are entitled to rely upon in good faith.

The Audit Committee Mandate is attached hereto as Appendix A.

Relevant Education and Experience of Audit Committee Members

The following is a brief summary of the education or experience of each member of the Audit Committee that is relevant to the performance of his or her responsibilities as a member of the Audit Committee, including any education or experience that has provided the member with an understanding of the accounting principles used by us to prepare our annual and interim consolidated financial statements.

Name of Audit Committee Member	Relevant Education and Experience
Mike Jackson	Mr. Mike Jackson worked in the banking sector from 1984 until his retirement in 2016 and brings more than 30 years of financial experience in corporate and investment banking. From 1997 to 2016, he was Managing Director in Scotiabank's Corporate & Investment Banking group focused on the oil & gas industry, including ten years heading the group. For the period 2006-2016, Mr. Jackson served as Financial Advisor to Boards/companies on M&A transactions aggregating over $28 billion. Mr. Jackson joined the Board of Veren in November 2016.
	Mr. Jackson holds a Bachelor of Science degree and a Master of Business Administration, both from Dalhousie University and the ICD.D designation granted by the Institute of Corporate Directors. Additionally, Mr. Jackson completed the Executive Management Program at Queen's University.
Corey Bieber	Mr. Bieber has over 35 years of financial and management experience within the energy industry. Most recently, Mr. Bieber served as an external Finance Committee member at TransMountain Corporation from 2023-2024. Prior thereto, he held progressively senior roles at Canadian Natural Resources Ltd. ("CNRL"), culminating in him serving as Chief Financial Officer from 2012-2018 and as an Executive Advisor from 2018-2022. Mr. Bieber also served as a board member on several CNRL subsidiaries and acted as Audit Committee chair for certain equity accounted investees. Prior to joining CNRL, he was Director of Financial Reporting at Enbridge Inc.
	Mr. Bieber holds a Bachelor of Commerce degree from the University of Calgary and has a Chartered Professional Accountant designation.
Jodi J. Jenson Labrie	Ms. Jenson Labrie is a highly accomplished financial executive with over 25 years of energy and professional services experience. Ms. Jenson Labrie most recently served as the Senior Vice President and Chief Financial Officer of Enerplus Corporation, an independent North American exploration and production company, from 2015 until the company's combination with Chord Energy in 2024. Prior thereto, she progressed through various leadership roles at Enerplus, including serving as Vice President of Finance from 2013-2015. Prior to joining Enerplus, Ms. Jenson Labrie was a Senior Manager at KPMG LLP specializing in Assurance and Financial Advisory Services.
	Ms. Jenson Labrie holds a Bachelor of Commerce from the University of Calgary (Distinction) and both a Chartered Professional Accountant and a Chartered Business Valuator designation. She is a member of the University of Calgary Board of Governors, where she chairs the Budget Committee and serves on the Finance & Property and Audit Committees.
François Langlois	Mr. Langlois is an oil and gas executive who brings over 35 years of domestic and international experience to the Veren Board, most recently from his role as Senior Vice President, Exploration & Production with Suncor Energy Inc., where he was responsible for the financial and operating performance of the group from 2011 until his retirement in 2016. Prior thereto, he was Vice President, Unconventional Gas from 2009 to 2010 and held various roles with Petro-Canada from 1982 to 2009, including as Vice President, Western Canada Production & North American Exploration.
	Mr. Langlois holds a Bachelor Geological Engineering from Laval University (Quebec City) and the ICD.D designation granted by the Institute of Corporate Directors.
Myron M. Stadnyk	Mr. Myron M. Stadnyk has over 40 years of oil and gas experience and is the former President and CEO of ARC Resources Ltd. His extensive career also includes working for a major oil and gas company in both domestic and international operations.
	Mr. Stadnyk earned a Bachelor of Science in Mechanical Engineering from the University of Saskatchewan and is a graduate of the Harvard Business School Advanced Management Program. He holds an ICD.D designation and is a member of APEGA. Mr. Stadnyk previously served on the Board of Directors at PrairieSky Royalty Ltd. and ARC Resources. Additionally, he dedicated over a decade as a Governor for CAPP. Currently, Mr. Stadnyk is the Chair of the Board for Vermilion Energy Inc. and serves on the Board of Trustees for the University of Saskatchewan Engineering Advancement Trust.

External Auditor Services Fees

For services provided to the Corporation and its subsidiaries for the years ended December 31, 2024 and 2023 PricewaterhouseCoopers LLP billed approximately $2,124,883 and $1,656,373, respectively, as detailed below:

		Year ended December 31		
		2024		2023
PricewaterhouseCoopers				
Audit fees	$	1,731,359	$	1,457,676
Audit-related fees	$	380,774	$	48,897
Tax fees	$	—	$	—
All other fees	$	12,750	$	149,800
Total	$	2,124,883	$	1,656,373

The Chair of the Audit Committee has the authority to pre-approve non-audit services which may be required from time to time.

Audit Fees were paid, or are payable, for professional services rendered by the auditors for the audit of the annual financial statements and reviews of the quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements. 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 in this category include participation fees levied by the Canadian Public Accountability Board. All Other Fees were for products or services provided by Veren's auditors other than those described as Audit Fees and Audit-Related Fees. All services described beside the captions "Audit Fees", "Audit-Related Fees", and "All Other Fees" were approved by the Audit Committee in compliance with paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X under the Exchange Act. None of the fees described above were approved by the Audit Committee pursuant to paragraph (c)(7)(i)(C) of Regulation S-X under the Exchange Act.

Audit Committee Oversight

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

TRANSFER AGENT AND REGISTRARS

The transfer agent and registrar for our Common Shares is Computershare Trust Company of Canada in Calgary, Alberta.

AUDITOR

Our auditor is PricewaterhouseCoopers LLP, Chartered Professional Accountants, 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3.

MATERIAL CONTRACTS

During the year ended December 31, 2024, Veren did not enter into any material contracts, nor are there any contracts still in effect, that are material to Veren, other than contracts entered into in the ordinary course of business.

INTERESTS OF EXPERTS

Audit of the consolidated financial statements and the effectiveness of internal control over financial reporting is conducted in accordance with PCAOB standards.

The Corporation's independent registered public accounting firm is PricewaterhouseCoopers LLP, Chartered Professional Accountants, who have issued a Report of Independent Registered Public Accounting Firm dated February 26, 2025 in respect of the Corporation's consolidated financial statements as at December 31, 2024 and December 31, 2023 and for each of the years ended December 31 and on the effectiveness of internal control over financial reporting as at December 31, 2024. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada, including the Rules of Professional Conduct with Guidance Chartered Professional Accountants of Alberta and any applicable legislation or regulations, as well as the rules of the US Securities and Exchange Commission (SEC) and the Public Company Accounting Oversight Board (PCAOB) on auditor independence.

Reserve estimates contained in this AIF are derived from reserve reports prepared by McDaniel. As of the date hereof, McDaniel, as a group, does not beneficially own, directly or indirectly, any Common Shares.

ADDITIONAL INFORMATION

Additional financial information is available on SEDAR+ at www.sedarplus.com, on EDGAR at www.sec.gov/edgar and on our website at www.vrn.com.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in our information circular in respect of the annual meeting of Shareholders held on May 10, 2024, which is available on SEDAR+. Additional financial information is provided in our comparative consolidated financial statements for our most recently completed financial year ended December 31, 2024 and MD&A.

For additional copies of this AIF please contact:

Veren Inc.
2000, 585 – 8th Avenue, S.W.
Calgary, Alberta
T2P 1G1

Attention: Investor Relations

APPENDIX A

VEREN INC.

AUDIT COMMITTEE MANDATE

CORPORATE POLICIES & PROCEDURES

I. THE BOARD OF DIRECTORS' MANDATE FOR THE AUDIT COMMITTEE

1. General

The Board of Directors (the "Board") has responsibility for the stewardship of Veren Inc. ("Veren") and its subsidiaries or related entities (collectively referred to herein as the "Corporation"). To discharge that responsibility, the Board is obligated by the *Business Corporations Act* (Alberta) to supervise the management of the business and affairs of the Corporation. The Board's supervisory function involves Board oversight or monitoring of all significant aspects of the management of the Corporation's business and affairs.

Public financial reporting and disclosure by the Corporation are fundamental to the Corporation's business and affairs and to its status as a publicly listed enterprise. The objective of the Board's monitoring of the Corporation's financial reporting and disclosure is to gain reasonable assurance of the following (including, where advisable in the achievement of this objective, through appropriate consultation with senior management and the Corporation's external auditors):

(a) that the Corporation complies with all applicable laws, regulations, rules, policies and other requirement of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;

(b) that the accounting principles, significant judgments and disclosures which underlie or are incorporated in the Corporation's consolidated financial statements are the most appropriate in the prevailing circumstances;

(c) that the Corporation's quarterly and annual consolidated financial statements and management's discussion and analysis, and the Corporation's Annual Information Forms ("AIF") are accurate within a reasonable level of materiality and present fairly the Corporation's financial position and performance in accordance with the recognition and measurement principles of International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"); and

(d) that appropriate information concerning the financial position and performance of the Corporation is disseminated to the public in a timely manner in accordance with corporate and securities law and with stock exchange regulations.

The Board is of the view that monitoring the Corporation's financial reporting and disclosure policies and procedures cannot be reliably met unless the following activities (the "Fundamental Activities") are conducted effectively:

(i) the Corporation's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Corporation's financial transactions;

(ii) the internal financial controls are regularly assessed for effectiveness and efficiency;

(iii) the Corporation's accounting functions are performed in a manner sufficient to ensure the Corporation has established and continues to maintain disclosure controls and procedures and internal control over financial reporting that meet the requirements of applicable laws, rules and regulations and allows the Chief Executive Officer and the Chief Financial Officer to certify the same;

(iv) the Corporation's quarterly and annual consolidated financial statements are properly prepared by management to comply with IFRS; and

(v) the Corporation's quarterly and annual consolidated financial statements and Management Discussion and Analysis ("MD&A") are reported on by an external auditor appointed by the shareholders of the Corporation.

To assist the Board in monitoring the Corporation's financial reporting and disclosure and to conform to applicable corporate and securities law, including National Instrument 52-110 *Audit Committees* ("**NI 52-110**") (as implemented by the Canadian Securities Administrators and as amended from time to time) the Board has established the Audit Committee (the "Committee") of the Board.

2. Role of the Committee

The role of the Committee is to assist the Board in its oversight of: (i) the integrity of the financial and related information of the Corporation, including its consolidated financial statements, the internal controls and procedures for financial reporting and the processes for monitoring compliance with legal and regulatory requirements; (ii) the Corporation's supply chain management process and procedures; (iii) the Corporation's enterprise risk management policy and framework; and (iv) the independence, qualifications and performance of the external auditor of the Corporation. Management is responsible for establishing and maintaining those controls, procedures and processes and the Committee is appointed by the Board to review and monitor them.

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.

3. Composition of Committee

(a) The Committee shall be appointed annually by the Board and consist of at least three members (the "Members") from among the directors of the Corporation.

(b) Each Member must be an independent, non-executive director, free from any relationship that would interfere with the exercise of the Member's independent judgement. Members shall meet the independence and experience requirements set forth in NI 52-110 and of the regulatory bodies to which the Corporation is subject. Each Member shall be "financially literate", which means under NI 52-110 having the ability to read and understand a set of financial statements that present a breadth and level of complexity of finance and accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements at the time of the Member's appointment to the Committee. At least one Member shall have accounting or related financial management expertise and qualify as an "audit committee financial expert" or similar designation in accordance with the requirements of the regulatory bodies to which the Corporation is subject.

(c) 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, and the rules, if any, adopted by the U.S. Securities and Exchange Commission 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 a Committee member receives from the Corporation.

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

(e) 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.

(f) The Board shall designate the Chair of the Committee.

(g) The Chair of the Board shall be an *ex officio* member of the Committee and shall be entitled to attend all meetings of the Committee.

(h) In the event of either: (i) a vacancy arising in the Committee that reduces the size of the Committee to fewer than three members; or (ii) the loss of independence of any Member, the Committee will fill the vacancy or replace the Member that has lost independence, as applicable, within six weeks or by the following annual shareholders' meeting if sooner.

4. Reliance on Experts

In contributing to the Committee discharging its duties under this Mandate, each Member of the Committee shall be entitled to rely in good faith upon:

(a) consolidated financial statements of the Corporation represented to the Member by an officer of the Corporation or in a written report of the external auditors to present fairly the financial position of the Corporation in accordance with IFRS; and

(b) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

5. Limitations on The Committee's Duties

In contributing to the Committee discharging its duties under this Mandate, each Member shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this Mandate is intended, or may be construed, to impose on any Member a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively, that the objectives of the Corporation's financial reporting are being met and to enable the Committee to report thereon to the Board.

II. AUDIT COMMITTEE MANDATE

This Mandate outlines how the Committee will satisfy the requirements set forth by the Board in its mandate.

1. Operating Principles

The Committee shall fulfill its responsibilities within the context of the following principles.

Committee Values

The Committee expects the management of the Corporation to operate in compliance with corporate policies; to comply with laws and regulations governing the Corporation; and to maintain strong financial reporting and control processes.

Communications

The Committee and its Members expect to have direct, open and frank communications throughout the year with management, other Committee Chairs, the external auditors, and other key Committee advisors or Company staff members as applicable.

Delegation

The Committee may delegate, from time to time, to any person or committee of persons any of the Committee's responsibilities that may be lawfully delegated.

Annual Audit Committee Plan

The Committee, in consultation with management and the external auditors, shall develop an annual Audit Committee plan responsive to the Committee's responsibilities as set out in this Mandate. In addition, the Committee, in consultation with management and the external auditors, shall develop and participate in a process for review of important financial topics that have the potential to impact the Corporation's financial disclosure.

The plan will be focused primarily on the annual and interim consolidated financial statements and MD&A of the Corporation; however, the Committee may at its sole discretion, or the discretion of the Board, review such other matters as may be necessary to satisfy the requirements of this Mandate.

Committee Expectations and Information Needs

The Committee shall communicate its expectations to management and the external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at a reasonable time in advance of meeting dates.

Access to Independent Advisors

To assist the Committee in discharging its responsibilities, the Committee may at its discretion, in addition to the external auditors, at the expense of the Corporation, retain one or more persons, firms or corporations having special expertise.

Reporting to the Board, Shareholders and Others

The Committee, through its Chair, shall report after each Committee meeting to the Board at the Board's next regular meeting. In addition, the Committee shall prepare a report to shareholders or others, concerning the Committee's activities in the discharge of its responsibilities, when and as required by applicable laws, rules, policies or regulations.

Evaluation

The Committee will conduct and present to the Board an annual evaluation of the performance of the Committee and the adequacy of this Mandate and recommend any proposed changes to the Board for approval.

Access to the Committee

Representatives of the Auditor and management of the Corporation shall have access to the Committee each in absence of the other.

The External Auditors

The Committee expects that, in discharging their responsibilities to the shareholders, the external auditors shall be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues, either specific to the Corporation or to the financial reporting environment in general, to the Committee.

No Alteration

No alteration to the roles and responsibilities of the Committee shall be effective without the approval of the Board.

2. Operating Procedures

Meetings

The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chair, upon the request of two (2) Members or at the request of the external auditors.

Quorum

A quorum shall be a majority of the Members.

Notice of Meeting

Notice of the time and place of every meeting shall be given in writing by any means of transmitted or recorded communication, including email or other electronic means that produces a written copy, to each Member of the Committee at least 24 hours prior to the time fixed for such meeting; provided however, that a Member may in any manner waive a notice of the meeting. Attendance of a Member at a meeting constitutes 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 is not lawfully called.

Meeting Agenda

Committee meeting agendas shall be the responsibility of the Chair of the Committee in consultation with other Members, senior management and the external auditors.

Procedure, Records and Reporting

Subject to any statute or the articles and by-laws of the Corporation, the Committee shall fix its own procedures at meetings, keep records of its proceedings and report to the Board when the Committee may deem appropriate (but not later than the next regularly scheduled meeting of the Board).

In Camera Meetings

At the discretion of the Committee, the Members shall meet in private session with the external auditors and with management only.

Referral to the Board

Any matter the Committee does not unanimously approve will be referred to the Board for consideration.

Secretary

Unless the Committee otherwise specifies, the Corporate Secretary (or the Associate General Counsel or other person authorized by the Corporate Secretary and acceptable to the Chair of the Committee) of the Corporation shall act as Secretary of all meetings of the Committee.

Acting Chair

In the absence of the Chair of the Committee, the Members shall appoint an acting Chair.

Minutes

A copy of the minutes of each meeting of the Committee shall be provided to each Member and to each director of the Corporation in a timely fashion.

Attendance at Meetings

The Chief Executive Officer, the Chief Financial Officer, the Senior Vice President, Finance and Treasurer and the internal audit staff are expected to be available to attend the Committee's meetings or portions thereof, and the Chief Executive Officer is entitled to attend all meetings of the Committee.

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.

3. Specific Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall:

Financial Information and Reporting

(a) Review, prior to public release, the Corporation's annual and quarterly consolidated financial statements with management and the external auditors to gain reasonable assurance that the statements are accurate within reasonable levels of materiality, complete, represent fairly the Corporation's financial position and performance and are in accordance with IFRS and report thereon to the Board before such consolidated financial statements are approved by the Board;

(b) Receive from the external auditors reports on their review of the annual and quarterly consolidated financial statements;

(c) Receive from management a copy of the representation letter provided to the external auditors and receive from management any additional representations required by the Committee;

(d) Review, prior to public release, all news releases issued by the Corporation with respect to the Corporation's annual and quarterly consolidated financial statements; and

(e) Review, prior to public release, prospectuses, material change disclosures of a financial nature, management discussion and analysis, AIF and similar disclosure documents to be issued by the Corporation.

Accounting Policies

(a) Review with management and the external auditors the appropriateness of the Corporation's accounting policies, disclosures, reserves, key estimates and judgments, including changes or variations thereto;

(b) Obtain reasonable assurance that the accounting policies, disclosures, reserves, key estimates and judgments are in compliance with IFRS from management and external auditors and report thereon to the Board;

(c) Review with management and the external auditors the degree of conservatism of the Corporation's underlying accounting policies, key estimates and judgments and reserves along with quality of financial reporting; and

(d) Participate, if requested, in the resolution of disagreements between management and the external auditors.

Risk and Uncertainty

(a) Acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Corporation, determine the Corporation's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:

(i) reviewing with management the Corporation's tolerance for financial risks;

(ii) reviewing with management its assessment of the significant financial risks facing the Corporation;

(iii) reviewing with management the Corporation's policies and any proposed changes thereto for managing those significant financial risks; and

(iv) reviewing with management its plans, processes and programs to manage and control such risks.

(b) Review with management its assessment of the cyber risks facing the Corporation and any related policies and any proposed changes thereto for managing cyber risk;

(c) Review, at least biennially, review the enterprise risk management policy, processes and framework and the assessment of enterprise risk management effectiveness by internal audit;

(d) Annually review the report prepared in accordance with the *Fighting Against Force Labour and Child Labour in Supply Chains Act* on the steps the Corporation has taken during its previous financial year to prevent and reduce the risk that forced labour or child labour is used at any step in the Corporation's supply chain and recommend to the Board that the report be approved by the Board in discharging its duty under the Act;

(e) Review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

(f) Review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;

(g) Review the adequacy of insurance coverages maintained by the Corporation; and

(h) Review regularly with management, the external auditors and the Corporation's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or operating results of the Corporation and the manner in which these matters have been disclosed in the consolidated financial statements.

Financial Controls and Control Deviations

(a) Review the plans of the external auditors to gain reasonable assurance that the evaluation and testing of internal financial controls is comprehensive, coordinated and cost effective;

(b) Receive regular reports from management and the external auditors on all significant deviations from IFRS or other Company internal control processes or indications which may suggest fraud and the corrective activity undertaken in respect thereto; and

(c) Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Board or the Committee concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgment, through existing reporting structures in the Corporation.

Compliance with Laws and Regulations

(a) Receive and review regular reports from management and others (e.g. external auditors) with respect to the Corporation's compliance with laws and regulations having a material impact on the consolidated financial statements including:

(i) tax and financial reporting laws and regulations;

(ii) legal withholding requirements; and

(iii) other laws and regulations which expose directors to liability; and

(b) Review the filing status of the Corporation's tax returns and those of its subsidiaries or related entities.

Relationship and 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) Recommend to the Board the nomination of the external auditors;

(c) Pre-approve and recommend to the Board the remuneration and the terms of engagement of the external auditors as set forth in the Engagement Letter. The Chair of the Committee hereby has the authority to pre-approve non-audit services which may be required from time to time;

(d) Review the performance of the external auditors annually or more frequently as required;

(e) Receive annually from the external auditors an acknowledgement in writing that the shareholders, as represented by the Board and the Committee, are their primary client;

(f) Receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non-audit services by the Corporation;

(g) Review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditors propose to employ;

(h) Meet with the external auditors at least once a year in the absence of management to determine,*inter alia*, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee;

(i) Establish effective communication processes with management and the Corporation's external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee; and

(j) Establish a reporting relationship between the external auditors and the Committee such that the external auditors can bring directly to the Committee matters that, in the judgment of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee of any disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved.

Relationship with Internal Auditor

(a) Review the internal audit staff functions, including:

(i) the purpose, authority and organizational reporting lines;

(ii) the annual audit plan, budget and staffing; and

(iii) the appointment and compensation of any person with the responsibility for the Internal Audit; and

(b) Review, with the Chief Financial Officer, controller or others, as appropriate, the Corporation's internal system of audit controls and the results of internal audits.

Other Responsibilities and Procedures

(a) After consultation with the Chief Financial Officer, the Senior Vice President Finance and Treasurer and the external auditors, gain reasonable assurance, at least annually, of the quality and sufficiency of the Corporation's accounting and financial personnel and other resources;

(b) Investigate any matters that, in the Committee's discretion, fall within the Committee's duties;

(c) Determine the appropriate funding for payment by the Corporation of: (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; and

(d) Perform such other functions as may, from time to time, be assigned to the Committee by the Board.

III. HIRING GUIDELINES FOR INDEPENDENT AUDITOR EMPLOYEES

1. Guidelines

The Committee has adopted the following guidelines regarding the hiring of any partner, employee, reviewing tax professional or other person providing audit assurance to the external auditor of the Corporation on any aspect of its certification of the Corporation's consolidated financial statements:

(a) No senior member of the audit team that is auditing a business of the Corporation can be hired into that business or into a position to which that business reports for a period of two years after the audit; and

(b) No former partner or employee of the external auditor may be made an officer of the Corporation or any of its subsidiaries for two years following association with the external auditor:

(i) The Chief Executive Officer must approve all office hires from the external auditor; and

(ii) The Chief Financial Officer must report annually to the Committee on any hires within these guidelines during the preceding year.

2. Audit Partner Rotation

The Committee will ensure that the head audit partner assigned by the external auditor to the Corporation, as well as the audit partner charged with reviewing the audit of the Corporation, are changed at least every five years.

3. Process for Handling Complaints about Accounting Matters

The Committee will establish the following procedures for the receipt and treatment of any complaint received by the Corporation, including confidential, anonymous submissions by employees of the Corporation and by third parties, regarding accounting, internal accounting controls, auditing or other matters and create a summary of any significant investigations regarding such matters:

(a) The Corporation will publish on its website special mail and e-mail addresses and a toll-free telephone number for receiving complaints regarding accounting, internal accounting controls, auditing matters and other matters;

(b) Copies of all complaints will be sent to the Chair of the Committee and to the Chair of the Board and to the Chair of those other committees of the Board responsible for the oversight of the subject matter of the complaint;

(c) Copies of complaints relating to accounting, internal accounting controls and auditing matters received will be sent to the Members of the Committee;

(d) All complaints will be investigated by the Corporation's finance and legal departments in the normal manner, except as otherwise directed by the Committee. The Committee may request that outside advisors be retained to investigate any complaint; and

(e) The status of each complaint will be reported on a quarterly basis to the Committee and, if the Committee so directs, to the full Board.

APPENDIX B

RESERVES COMMITTEE MANDATE

CORPORATE POLICIES & PROCEDURES

PURPOSE

The Reserves Committee (the "Committee") is appointed by the Board of Directors of Veren Inc. (the "Board") to assist the Board in fulfilling its responsibility for the stewardship of Veren Inc. ("Veren") and its subsidiaries or related entities (collectively referred to herein as the "Corporation"). The Committee's primary duties and responsibilities are to assume responsibility for assisting the Board in respect of the annual independent review of Veren's petroleum and natural gas reserves and reporting to the Board in respect thereof, including assisting the Board in meeting its obligations under National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*, (as implemented by the Canadian Securities Administrators and as amended from time to time) (**"NI 51-101"**).

RESERVES COMMITTEE RESPONSIBILITIES AND DUTIES

The overall duties and responsibilities of the Committee shall be as follows:

(a) in conjunction with the Corporation's senior engineering management, meet with the independent evaluating engineers being considered for appointment and review their qualifications and independence to ensure the independent evaluating engineers being considered for appointment are technically qualified and competent and are independent of management;

(b) establish the terms of the engagement of the independent evaluating engineers;

(c) after consultation with the Corporation's senior engineering management, recommend to the Board the appointment of the independent evaluating engineers to assist the Corporation in the annual review of its petroleum and natural gas reserves;

(d) in consultation with the Corporation's senior engineering management determine the scope of the annual review of the petroleum and natural gas reserves by the independent evaluating engineers, having regard to the regulatory reporting requirements applicable to the Corporation, including those set forth in NI 51-101;

(e) review, with reasonable frequency, the Corporation's procedures for providing petroleum and natural gas reserves information to the qualified independent evaluating engineers who report on reserves data for the purposes of NI 51-101, and the information used by the independent evaluating engineers to enable the independent evaluating engineers to provide a report that will meet regulatory reporting requirements;

(f) in consultation with the Corporation's senior engineering management and the independent evaluating engineers:

- determine whether any restrictions affect the ability of the independent evaluating engineers to report on reserve data without reservations; and
- review the reserves data and the report of the independent evaluating engineers.

(g) ensure the disclosure to the public on the Corporation's petroleum and natural gas reserves is in compliance with regulatory requirements and make appropriate changes, reports or recommendations to the Board with respect to the procedures for such disclosure;

(h) review any proposal to change the independent evaluating engineers and/or resolve any differences between the independent evaluating engineers and management;

(i) meet on an annual basis with the Corporation's senior engineering management and/or the independent evaluating engineers of the Corporation to review and consider the evaluation of the Corporation's petroleum and natural gas reserves;

(j) meet separately with the independent evaluating engineers and/or senior engineering management when the Committee deems it desirable and advise the Board on the results of such meeting;

(k) coordinate meetings with the Audit Committee of the Corporation, the Corporation's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Corporation's evaluation of petroleum and natural gas reserves;

(l) review at least biennially this Committee mandate and recommend any changes to the Board; and

(m) to maintain minutes of meetings and periodically report to the Board on significant results of the foregoing activities.

COMMITTEE MEMBERS' DUTIES IN ADDITION TO THOSE OF DIRECTOR

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

REPORTING

The Committee shall report to the Board. The Committee shall provide the Board with a summary of all meetings held at a regularly scheduled meeting of the Board held following any Committee meetings.

COMPOSITION

The Committee will be comprised of at least three members, as determined by the Board. The Committee members shall satisfy the independence and experience requirements of applicable securities laws, rules, or guidelines, any applicable stock exchange requirements or guidelines and any other applicable regulatory rules. In particular, a majority of the members of the Committee shall be free from any relationship which could reasonably be expected to materially interfere with the member's independent judgment. Determinations as to whether a particular director satisfies the requirements for membership on the Committee shall be made by the full Board and shall be reviewed at least annually.

The Chair of the Board shall be an *ex officio* member of the Committee and shall be entitled to attend all meetings of the Committee.

Committee members will include only duly-elected directors. Members of the Committee shall be appointed from time to time by the Board. Each member shall serve until such member's successor is appointed, unless such member resigns or is removed by the Board or such member otherwise ceases to be a director of the Corporation. If a member of the Committee ceases to be independent for reasons outside that member's reasonable control, the member shall immediately notify the Chair of the Board as to this fact and shall resign such member's position on the Committee on the earliest of (i) the appointment of such member's successor; (ii) the next annual meeting of shareholders of the Corporation; and (iii) the date that is six months from the occurrence of the event which caused the member to not be independent. The Board shall fill any vacancy if the membership of the Committee is less than three directors.

CHAIR

The Board shall appoint the Chair of the Committee or, if it does not do so, the members of the Committee may elect a Chair by a vote of a majority of the full Committee membership. The Chair shall be an independent director. If the Chair of the Committee is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting shall be chosen to preside by a majority of the members of the Committee present at such meeting.

SECRETARY

The Corporate Secretary of the Corporation, the Associate General Counsel or such other person as the Corporate Secretary of the Corporation shall designate from time to time, shall be the Secretary of the Committee and shall keep minutes of the meetings of the Committee.

OPERATION OF COMMITTEE MEETINGS

The Committee shall have access to such officers and employees of the Corporation and to such information respecting the Corporation, as it considers necessary or advisable in order to perform its duties and responsibilities. The Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensation for any such counsel and advisors, such engagement to be for the Corporation's sole account and expense.

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

Meetings of the Committee shall be conducted as follows:

(1) The Committee shall meet at least two times annually at such times and at such locations as the Chair of the Committee shall determine. Any two members of the Committee may also request a meeting of the Committee.

(2) The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or by other telecommunication device that permits all persons participating in the meeting to hear each other.

(3) The Chair shall, in consultation with management, establish the agenda for the meetings and instruct management to ensure that properly prepared agenda materials are circulated to the Committee with sufficient time for study prior to the meeting.

(4) Every question at a Committee meeting shall be decided by a majority of the votes cast.

(5) The Chief Executive Officer is 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, provided that the Chief Executive Officer of the Corporation is entitled to attend all meetings 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.

(6) The Committee may delegate from time to time to any person or committee of persons any of the Committee's responsibilities that lawfully may be delegated.

(7) 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 the Committee meeting shall be sent firstly to the Chair and next to all Committee members.

NOTICE OF MEETING

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

A member may in any manner waive notice of the 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.

MISCELLANEOUS

The Committee, with unanimity, may engage outside resources if deemed advisable. Lack of unanimity requires that the matter be referred to the Nominating and Corporate Governance Committee.

Appendix C

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

To the Board of Directors of Veren Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, estimated using forecast prices and costs.

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

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

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

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

			Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel	December 31, 2024	Canada	—	14,039,820.3	—	14,039,820.3

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

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

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd.

ORIGINALLY SIGNED BY

Michael Verney, P.Eng.
Executive Vice President

Calgary, Alberta, Canada
January 20, 2025

Appendix D

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Veren 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.

McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator, has evaluated the Corporation's reserves data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation has:

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

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

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

The Reserves Committee of the board of directors 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 Reserves Committee, approved:

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

(b) the filing of Form 51-101F2 which is 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.

"Craig Bryksa"	*"Ryan Gritzfeldt"*
CRAIG BRYKSA President and Chief Executive Officer	RYAN GRITZFELDT Chief Operating Officer
"François Langlois"	*"Barbara Munroe"*
FRANÇOIS LANGLOIS Director	BARBARA MUNROE Chair of the Board

February 26, 2025

Exhibit 99.2

MANAGEMENT'S REPORT

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Veren Inc. is responsible for the preparation of the consolidated financial statements. The consolidated financial statements have been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect management's best estimates and judgments. Management has determined such amounts on a reasonable basis in order to determine that the consolidated financial statements are presented fairly in all material respects.

PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants, was appointed by a resolution of the Board of Directors to audit the consolidated financial statements of the Company and to provide an independent professional opinion. PricewaterhouseCoopers LLP was appointed to hold such office until the next annual meeting of the shareholders of the Company.

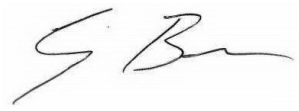
The Board of Directors, through its Audit Committee, has reviewed the consolidated financial statements including notes thereto with management and PricewaterhouseCoopers LLP. The members of the Audit Committee are composed of independent directors who are not employees of the Company. The Audit Committee meets regularly with management and PricewaterhouseCoopers LLP to review and approve the consolidated financial statements. The Board of Directors has approved the information contained in the consolidated financial statements based on the recommendation of the Audit Committee.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is also responsible for establishing and maintaining an adequate system of internal control over financial reporting that is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Management has assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2024. The assessment was based on 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. Management concluded that this system of internal controls was effective as of December 31, 2024. The Company has effective disclosure controls and procedures to ensure timely and accurate disclosure of material information relating to the Company which complies with the requirements of Canadian securities legislation and the United States Sarbanes - Oxley Act of 2002.

PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants who also audited the Company's consolidated financial statement for the year ended December 31, 2024, has audited the effectiveness of the Company's internal control over financial reporting as at December 31, 2024.



Craig Bryksa
President and Chief Executive Officer



Ken Lamont
Chief Financial Officer

February 26, 2025



Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Veren Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting
We have audited the accompanying consolidated balance sheets of Veren Inc. and its subsidiaries (the Company) as of December 31, 2024 and 2023, and the related consolidated statements of comprehensive income, of changes in shareholders' equity and of cash flows for the years then ended, 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, 2024, 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, 2024 and 2023, and its financial performance and its cash flows for the years then ended in conformity with IFRS Accounting 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, 2024, based on criteria established in *Internal Control – Integrated Framework* (2013) issued by the COSO.

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 Report on 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 matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates 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 matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The impact of estimates of proved plus probable oil and gas reserves on development and production assets
As described in Notes 2, 3 and 10 to the consolidated financial statements, the Company had a net balance of $9,716.6 million for development and production assets as of December 31, 2024, and the related depletion expense for the year ended December 31, 2024 was $1,166.3 million. Development and production assets are measured at cost less accumulated depletion and any accumulated impairment losses. Development and production assets are depleted using the unit-of-production method based on estimated proved plus probable oil and gas reserves before royalties, as determined by independent petroleum reservoir engineers. Determining the Company's proved plus probable oil and gas reserves required the use of significant judgment and assumptions by management related to production forecasts, commodity prices, costs and related future cash flows. In determining the estimates of the proved plus probable oil and gas reserves, management utilizes the services of specialists, specifically independent petroleum reservoir engineers (management's specialists).

The principal considerations for our determination that performing procedures relating to the impact of estimates of proved plus probable oil and gas reserves on development and production assets is a critical audit matter are (i) the judgment by management, including the use of management's specialists, when developing the estimates of proved plus probable oil and gas reserves, and (ii) a high degree of auditor judgment, effort and subjectivity in performing procedures and evaluating assumptions used in developing those estimates, including production forecasts, commodity prices, costs and related future cash flows.

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 proved plus probable oil and gas reserves and the calculation of depletion expense. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the proved plus probable oil and gas reserves used to determine depletion expense. As a basis for using this work, management's specialists' qualifications were understood and the Company's relationship with management's specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by management's specialists, tests of the data used by management's specialists and an evaluation of management's specialists' findings. Evaluating the assumptions used by management's specialists related to production forecasts, commodity prices, costs and related future cash flows involved assessing whether the assumptions used were reasonable considering the current and past performance of the Company and whether they were consistent with industry pricing forecasts and evidence obtained in other areas of the audit, as applicable. Procedures were also performed to test the unit-of-production method used to calculate depletion expense.

/s/PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Canada
February 26, 2025

We have served as the Company's auditor since 2001.

CONSOLIDATED BALANCE SHEETS

As at December 31 (Cdn$ millions)	Notes	**2024**	2023
ASSETS			
Cash		**17.1**	17.3
Accounts receivable		**386.5**	377.9
Prepaids and deposits		**99.1**	87.8
Derivative asset	27	**166.9**	240.7
Other current assets	5	**7.2**	79.2
Assets held for sale		**—**	247.1
Total current assets		**676.8**	1,050.0
Derivative asset	27	**17.8**	14.3
Other long-term assets	6	**18.1**	7.4
Exploration and evaluation	7	**472.3**	607.0
Property, plant and equipment	8, 10	**9,753.2**	10,718.3
Right-of-use asset	14	**569.0**	102.8
Goodwill	11	**243.8**	275.9
Total assets		**11,751.0**	12,775.7
LIABILITIES			
Accounts payable and accrued liabilities		**493.5**	634.9
Dividends payable		**70.7**	56.8
Current portion of long-term debt	13	**514.4**	380.0
Derivative liability	27	**14.1**	51.4
Other current liabilities	12	**95.0**	118.0
Liabilities associated with assets held for sale		**—**	132.4
Total current liabilities		**1,187.7**	1,373.5
Long-term debt	13	**1,940.1**	3,186.3
Derivative liability	27	**16.4**	3.8
Other long-term liabilities	15	**24.2**	31.0
Lease liability	14	**551.6**	104.2
Decommissioning liability	8, 16	**560.0**	566.4
Deferred income tax	24	**710.0**	643.0
Total liabilities		**4,990.0**	5,908.2
SHAREHOLDERS' EQUITY			
Shareholders' capital	17	**16,959.7**	17,052.7
Contributed surplus		**14.5**	17.4
Deficit	18	**(10,213.2)**	(10,202.5)
Accumulated other comprehensive income		**—**	(0.1)
Total shareholders' equity		**6,761.0**	6,867.5
Total liabilities and shareholders' equity		**11,751.0**	12,775.7

Commitments (Note 29)
See accompanying notes to the consolidated financial statements.
Approved on behalf of the Board of Directors:



Barbara Munroe
Chair of the Board



Mike Jackson
Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (Cdn$ millions, except per share amounts)	Notes	**2024**	2023
REVENUE AND OTHER INCOME			
Oil and gas sales	31	**4,271.3**	3,499.0
Purchased product sales		**142.6**	66.2
Royalties		**(441.7)**	(375.3)
Oil and gas revenue		**3,972.2**	3,189.9
Commodity derivative gains (losses)	20, 27	**(14.6)**	163.8
Other income (loss)	21	**(17.0)**	13.4
		3,940.6	3,367.1
EXPENSES			
Operating		**941.4**	770.5
Purchased product		**142.8**	68.6
Transportation		**311.5**	174.3
General and administrative		**112.0**	126.5
Interest	22	**194.3**	129.4
Foreign exchange gain	23	**(6.0)**	(10.0)
Share-based compensation		**19.1**	38.7
Depletion, depreciation and amortization	7, 10, 14	**1,338.3**	894.7
Impairment	10, 11	**512.3**	93.8
Accretion and financing	14, 16	**31.2**	27.5
		3,596.9	2,314.0
Net income before tax from continuing operations		**343.7**	1,053.1
Tax expense (recovery)			
Current	24	**—**	(0.7)
Deferred	24	**59.8**	254.4
Net income from continuing operations		**283.9**	799.4
Net income (loss) from discontinued operations	9	**(10.6)**	(229.1)
Net income		**273.3**	570.3
Other comprehensive income			
Items that may be subsequently reclassified to profit or loss			
Foreign currency translation of foreign operations		**0.6**	1.3
Reclassification of cumulative foreign currency translation of discontinued foreign operations	9	**(0.5)**	(621.7)
Comprehensive income (loss)		**273.4**	(50.1)
Net income (loss) per share	26		
Continuing operations - basic		**0.46**	1.47
Discontinued operations - basic		**(0.02)**	(0.42)
Net income per share - basic		**0.44**	1.05
Continuing operations - diluted		**0.46**	1.46
Discontinued operations - diluted		**(0.02)**	(0.42)
Net income per share - diluted		**0.44**	1.04

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Cdn$ millions, except per share amounts)	Notes	Shareholders' capital	Contributed surplus	Deficit	Accumulated other comprehensive income	Total shareholders' equity
December 31, 2022		16,419.3	17.1	(10,563.3)	620.3	6,493.4
Issued for cash		500.1				500.1
Issued on capital acquisitions		493.0				493.0
Redemption of restricted shares		4.9	(4.9)	2.4		2.4
Common shares repurchased for cancellation		(349.9)				(349.9)
Share issue costs, net of tax		(15.4)				(15.4)
Share-based compensation			5.8			5.8
Stock options exercised		0.7	(0.6)			0.1
Net income				570.3		570.3
Dividends declared ($0.387 per share)				(211.9)		(211.9)
Foreign currency translation adjustment					1.3	1.3
Reclassification of cumulative foreign currency translation of discontinued foreign operations					(621.7)	(621.7)
December 31, 2023		17,052.7	17.4	(10,202.5)	(0.1)	6,867.5
Redemption of restricted shares	17	**5.6**	**(5.6)**	**0.6**		**0.6**
Common shares repurchased for cancellation	17	**(101.1)**				**(101.1)**
Share issue costs, net of tax	17	**(0.8)**				**(0.8)**
Share-based compensation			**5.7**			**5.7**
Stock options exercised	17	**3.3**	**(3.0)**			**0.3**
Net income				**273.3**		**273.3**
Dividends declared ($0.460 per share)				**(284.6)**		**(284.6)**
Foreign currency translation adjustment					**0.6**	**0.6**
Reclassification of cumulative foreign currency translation of discontinued foreign operations	9				**(0.5)**	**(0.5)**
December 31, 2024		**16,959.7**	**14.5**	**(10,213.2)**	**—**	**6,761.0**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 (Cdn$ millions)	Notes	**2024**	2023
CASH PROVIDED BY (USED IN):			
OPERATING ACTIVITIES			
Net income		**273.3**	570.3
Items not affecting cash			
Other loss	9, 21	**21.3**	4.2
Deferred tax expense	24	**59.8**	533.0
Share-based compensation		**5.6**	5.7
Depletion, depreciation and amortization	7, 10, 14	**1,338.3**	1,065.0
Impairment	10, 11	**512.3**	822.2
Accretion	16	**17.1**	22.7
Unrealized losses on derivatives	27	**55.4**	56.9
Translation of US dollar long-term debt	23	**155.6**	(16.8)
Reclassification of cumulative foreign currency translation of discontinued foreign operations	9	**(0.5)**	(621.7)
Translation of US dollar derivatives	27	**(6.3)**	0.9
Realized gain on cross currency swap maturity	23	**(103.9)**	(151.8)
Decommissioning expenditures	16	**(40.6)**	(40.0)
Change in non-cash working capital	30	**(175.6)**	(54.9)
		2,111.8	2,195.7
INVESTING ACTIVITIES			
Development capital and other expenditures	7, 10	**(1,587.8)**	(1,220.5)
Capital acquisitions, net of cash acquired	8	**(26.4)**	(3,616.2)
Capital dispositions	8	**1,037.7**	604.5
Other long-term assets	6	**(10.9)**	(0.8)
Change in non-cash working capital	30	**62.4**	(4.2)
		(525.0)	(4,237.2)
FINANCING ACTIVITIES			
Issue of shares, net of issue costs		**(0.8)**	479.7
Common shares repurchased for cancellation	17	**(101.1)**	(349.9)
Increase (decrease) in bank debt, net	30	**(1,874.3)**	2,675.1
Issuance of senior notes	13, 30	**1,000.0**	—
Repayment of senior notes and acquired long-term debt	30	**(392.9)**	(897.9)
Realized gain on cross currency swap maturity	23, 30	**103.9**	151.8
Payments on principal portion of lease liability	14, 30	**(41.0)**	(20.8)
Dividends declared	30	**(284.6)**	(211.9)
Change in non-cash working capital	30	**3.0**	(57.2)
		(1,587.8)	1,768.9
Impact of foreign currency on cash balances		**0.8**	—
DECREASE IN CASH		**(0.2)**	(272.6)
CASH AT BEGINNING OF YEAR		**17.3**	289.9
CASH AT END OF YEAR		**17.1**	17.3

See accompanying notes to the consolidated financial statements.

Supplementary Information:

Cash taxes refunded (paid)	**0.1**	(0.1)
Cash interest paid	**(202.4)**	(118.1)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2024 and 2023

1. STRUCTURE OF THE BUSINESS

On May 10, 2024, Crescent Point Energy Corp. changed its name to Veren Inc. (the "Company" or "Veren"). The principal undertaking of Veren and its subsidiaries is to carry on the business of acquiring, developing and holding interests in petroleum and natural gas properties.

Veren was amalgamated in Alberta, Canada under the *Business Corporations Act (Alberta)*. The address of the principal place of business is 2000, 585 - 8^{h} Ave S.W., Calgary, Alberta, Canada, T2P 1G1.

These annual consolidated financial statements were approved and authorized for issue by the Company's Board of Directors on February 26, 2025.

2. BASIS OF PREPARATION

a) Preparation

These consolidated financial statements are presented under IFRS Accounting Standards as issued by the International Accounting Standards Board. The policies applied in these consolidated financial statements are based on IFRS Accounting Standards issued and outstanding as of February 26, 2025.

The Company’s presentation currency is Canadian dollars and all amounts reported are Canadian dollars unless noted otherwise. References to “US$" and "US dollars" are to United States ("U.S.") dollars. Veren's Canadian operations are presented herein as continuing operations. The Company's U.S. operations have been classified and presented as discontinued operations. See Note 9 - "Discontinued Operations" for additional information.

b) Basis of measurement, functional and presentation currency

The Company’s 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 at the average rate over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income as cumulative translation adjustments.

c) Use of estimates and judgments

The preparation of consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future years affected.

The Company also faces uncertainties related to future environmental laws and climate-related regulations, which could affect the Company's financial position and future earnings. This transition to a lower-carbon society, as well as the physical impacts of climate change, could result in increased operating costs and reduced demand for oil and gas products. As a result, this could change a number of variables and assumptions used to determine the estimated recoverable amounts of the Company's oil and gas assets. The unpredictable nature, timing and extent of climate-related initiatives presents various risks and uncertainties, including to management's judgements, estimates and assumptions that affect the application of accounting policies. Significant estimates and judgments made by management in the preparation of these consolidated financial statements are outlined below.

Oil and gas activities

Reserves estimates, although not reported as part of the Company’s consolidated financial statements, can have a significant effect on net income, assets and liabilities as a result of their impact on depletion, depreciation and amortization (“DD&A”), decommissioning liability, deferred taxes, asset impairments and impairment reversals, and business combinations. Independent petroleum reservoir engineers perform evaluations of the Company’s oil and gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

For purposes of impairment testing, property, plant and equipment (“PP&E”) is aggregated into cash-generating units (“CGUs”), based on separately identifiable and largely independent cash inflows. The determination of the Company’s CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructure, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations.

The determination of technical feasibility and commercial viability, based on the presence of reserves and which results in the transfer of assets from exploration and evaluation ("E&E") to PP&E, is subject to judgment.

Decommissioning liability

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are impacted by estimates with respect to the cost and timing of decommissioning.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices, production forecasts, costs and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected as a result of changes in future DD&A, asset impairment or goodwill impairment.

Fair value measurement

The estimated fair value of derivative instruments resulting in derivative assets and liabilities, by their very nature, are subject to measurement uncertainty. Estimates included in the determination of the fair value of derivative instruments include forward benchmark prices, discount rates, share price, forward foreign exchange rates and forward interest rates.

Joint control

Judgment is required to determine when the Company has joint control over an arrangement, which requires an assessment of the capital and operating activities of the projects it undertakes with partners and when the decisions in relation to those activities require unanimous consent.

Share-based compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax assets and liabilities recognize the extent that temporary differences will be receivable and payable in future periods. The calculation of the asset and liability 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, expected cash flows from estimated proved plus probable reserves and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

3. MATERIAL ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently by the Company and its subsidiaries for all periods presented in these annual consolidated financial statements.

a) Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries and any reference to the “Company” throughout these consolidated financial statements refers to the Company and its subsidiaries. All transactions between the Company and its subsidiaries have been eliminated.

The Company conducts some of its oil and gas production activities through jointly controlled operations and the financial statements reflect only the Company's proportionate interest in such activities. Joint control exists for contractual arrangements governing the Company's assets whereby the Company has less than 100 percent working interest, all the partners have control of the arrangement collectively, and share the associated risks. The Company does not have any joint arrangements that are material to the Company or that are structured through joint venture arrangements.

b) Property, Plant and Equipment

Items of PP&E, which primarily consist of oil and gas development and production assets, are measured at cost less accumulated depletion, depreciation and any accumulated impairment losses or impairment reversals. Development and production assets are accumulated into CGUs and account for the cost of developing the commercial reserves and initiating production.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as development and production assets only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in net income as incurred. Capitalized development and production assets generally represent costs incurred in developing reserves and initiating or enhancing production from such reserves. The carrying amount of any sold component is derecognized.

Depletion and Depreciation

Development and production assets are depleted using the unit-of-production method based on estimated proved plus probable oil and gas reserves before royalties, as determined by independent petroleum reservoir engineers. Natural gas reserves and production are converted to equivalent barrels of oil based upon the relative energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing proved plus probable oil and gas reserves.

Corporate assets are depreciated on a straight-line basis over the estimated useful lives of the related assets, ranging from five to 16 years.

Impairment

The carrying amounts of PP&E, which takes into account the discounted abandonment and reclamation costs on proved plus probable undeveloped oil and gas reserves, are grouped into CGUs and reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income.

Assets are grouped into CGUs based on the integration between assets, shared infrastructure, the existence of common sales points, geography, geological structure and the manner in which management monitors and makes decisions regarding operations. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent petroleum reservoir engineers. The recoverable amount is the higher of fair value less costs of disposal and the value-in-use. Fair value less costs of disposal is categorized as Level 3 according to the IFRS 13 fair value hierarchy and is derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows from proved plus probable oil and gas reserves discounted at a pre-tax rate.

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, net of depletion, had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net income.

c) Exploration and Evaluation

E&E assets are comprised of the accumulated expenditures incurred in an area where technical feasibility and commercial viability has not yet been determined. E&E assets include undeveloped land and any drilling costs thereon.

Technical feasibility and commercial viability are considered to be determinable when reserves are discovered. Upon determination of reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E.

Costs incurred prior to acquiring the legal rights to explore an area are expensed as incurred.

Amortization

Undeveloped land classified as E&E assets is amortized by major area over the average primary lease term and recognized in net income. Drilling costs classified as E&E assets are not amortized, but are subject to impairment.

Impairment

E&E assets are reviewed quarterly for indicators of impairment and upon reclassification from E&E assets to PP&E. E&E assets are tested for impairment at the operating segment level by combining E&E assets with PP&E. The recoverable amount is the greater of fair value less costs of disposal or value-in-use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows from proved plus probable oil and gas reserves, plus the fair market value of undeveloped land. Value-in-use is assessed using the expected future cash flows from proved plus probable oil and gas reserves discounted at a pre-tax rate.

Impairments of E&E assets are reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been, net of amortization, had no impairment been recognized.

d) Decommissioning Liability

The Company recognizes the present value of a decommissioning liability in the period in which it is incurred. The obligation is recorded as a liability on a discounted basis using the relevant risk free rate, with a corresponding increase to the carrying amount of the related asset. Over time, the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the underlying proved plus probable oil and gas reserves. Accretion expense is recognized in net income. Revisions to the discount rate, estimated timing or amount of future cash flows would also result in an increase or decrease to the decommissioning liability and related asset.

e) Goodwill

The Company records goodwill relating to business combinations when the purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired business. The goodwill balance is assessed for impairment annually or as events occur that could result in impairment. Goodwill is tested for impairment at an operating segment level by combining the carrying amounts of PP&E, E&E assets and goodwill and comparing this to the recoverable amount. Any excess of the carrying amount over the recoverable amount is the impairment amount. The recoverable amount estimates are categorized as Level 3 according to the IFRS 13 fair value hierarchy. Impairment charges, which are not tax affected, are recognized in net income. Goodwill is reported at cost less any accumulated impairment. Goodwill impairments are not reversed.

f) Share-based Compensation

Restricted shares granted under the Restricted Share Bonus Plan are accounted for at fair value and vest on terms up to three years from the grant date, as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and recognized when they occur. The expense is recognized over the service period, with a corresponding increase to contributed surplus. The Company capitalizes the portion of share-based compensation directly attributable to development activities, with a corresponding decrease to share-based compensation expense. At the time the restricted shares vest, the issuance of shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus. Total dividends declared from the grant date are paid out on vesting and satisfied through cash payment or the issuance of additional common shares.

Employee Share Value Plan ("ESVP") awards are accounted for at fair value and vest on terms of up to three years from the grant date, as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the ESVP awards on the date of grant and subsequently adjusted to reflect the fair value at each period end. The expense is recognized over the service period, with a corresponding increase to long-term compensation liability. Forfeitures are estimated at the grant date and recognized when they occur. The Company capitalizes the portion of share-based compensation directly attributable to development activities, with a corresponding decrease to share-based compensation expense. ESVP awards are settled in cash upon vesting based on the prevailing Veren share price and the aggregate amount of dividends paid from the grant date.

Performance share units ("PSUs") are accounted for at fair value and vest on terms of up to three years from the grant date, as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the PSUs on the date of the grant and subsequently adjusted to reflect the fair value at each period end. Market performance conditions are factored into the fair value and the best estimate of non-market performance conditions is used to determine an estimate of the number of units that will vest. Fair value is based on the expected cash payment per PSU and the expected number of PSUs to vest, calculated from multipliers based on internal and external performance metrics. The expense is recognized over the service period, with a corresponding increase to long-term compensation liability. PSUs are settled in cash upon vesting based on the prevailing Veren share price, performance multiplier, and factors in the aggregate amount of dividends paid over the vesting term.

Deferred share units ("DSUs") are accounted for at fair value. Share-based compensation expense is determined based on the estimated fair value of the DSUs on the date of the grant and subsequently adjusted to reflect the fair value at each period end. Fair value is based on the prevailing Veren share price. DSUs vest immediately upon the date of grant and are cash settled on the date in which the non-employee director ceases to be a director of the Company. DSUs are settled in cash based on the prevailing Veren share price and factors in the aggregate amount of dividends paid from the grant date.

Stock options are accounted for at fair value with a maximum term of seven years, and vest on terms as determined by the Board of Directors. Share-based compensation expense is determined based on the estimated fair value of the stock options on the date of the grant. Upon vesting, the stock option holder may either exercise their stock options to purchase one common share per option at the exercise price or, at the Company's discretion, surrender their stock options for a cash payment in an amount equal to the aggregate positive difference, if any, between the market price and the exercise price of the number of common shares associated with the stock options surrendered. Alternatively, the stock option holder may also, at the Company's discretion, surrender their stock options for common shares having a value equivalent to the cash payment.

g) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the estimated effect of any differences between the accounting and tax basis of assets and liabilities, using enacted or substantively enacted income tax rates expected to apply when the deferred tax asset or liability is settled. The effect of a change in income tax rates on deferred income taxes is recognized in net income in the period in which the change occurs.

The tax expense for the period comprises current and deferred tax. Tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity. In this case, the tax is also recognized in other comprehensive income or directly in equity, respectively.

The Company is able to deduct certain settlements under its Restricted Share Bonus Plan. To the extent the tax deduction exceeds the cumulative remuneration cost for a particular restricted share grant recorded in net income, the tax benefit related to the excess is recorded directly within equity.

A deferred tax asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized. Deferred income tax assets and liabilities are presented as non-current.

h) Financial Instruments

The Company uses financial derivative instruments and physical delivery commodity contracts from time to time to reduce its exposure to fluctuations in commodity prices, share price, foreign exchange rates and interest rates. The Company also makes investments in companies from time to time in connection with the Company's acquisition and divestiture activities.

Financial derivative instruments

Financial derivative instruments are included in current assets/liabilities except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets/liabilities.

The Company has not designated any of its financial derivative contracts as effective accounting hedges and, accordingly, fair values its financial derivative contracts with the resulting gains and losses recorded in net income.

The fair value of a financial derivative instrument on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair values are based on quoted market prices where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at the reporting date.

Financial assets and liabilities

Financial assets and liabilities are measured at fair value on initial recognition. For non-equity instruments, measurement in subsequent periods depends on the classification of the financial asset or liability as "fair value through profit or loss" or "amortized cost".

Financial assets and liabilities classified as fair value through profit or loss are subsequently carried at fair value, with changes recognized in net income.

Financial assets and liabilities classified as amortized cost are subsequently carried at amortized cost using the effective interest rate method.

Currently, the Company classifies all non-equity financial instruments which are not financial derivative instruments as amortized cost.

At each reporting date, the Company assesses whether there is objective evidence that a financial asset carried at amortized cost is impaired. If such evidence exists, the Company recognizes an impairment loss in net income. Impairment losses are reversed in subsequent periods if the impairment loss decrease can be related objectively to an event occurring after the impairment was recognized.

For investments in equity instruments, the subsequent measurement is dependent on the Company's election to classify such instruments as fair value through profit or loss or fair value through other comprehensive income. Currently, the Company classifies all investments in equity instruments as fair value through profit or loss, whereby the Company recognizes movements in the fair value of the investment (adjusted for dividends) in net income. If the fair value through other comprehensive income classification is selected, the Company would recognize any dividends from the investment in net income and would recognize fair value re-measurements of the investment in other comprehensive income.

Impairment of financial assets

Impairment losses are recognized using an expected credit loss model. The Company has adopted the simplified expected credit loss model for its accounts receivable, which permits the use of the lifetime expected loss provision.

To measure the expected credit losses, accounts receivable have been grouped based on shared credit risk characteristics and days past due. The Company uses judgment in making these assumptions and selecting the inputs into the expected loss calculation based on past history, existing market conditions and forward-looking estimates at the end of each reporting period.

i) Business Combinations

Business combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The acquisition is measured as the fair value of the acquired assets by estimating the discounted after-tax future net cash flows, the fair value of equity instruments issued and the fair value of liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in net income. Transaction costs associated with business combinations are expensed as incurred.

j) Foreign Currency Translation

Foreign operations

The Company has operations in the U.S. transacted via U.S. subsidiaries. The assets and liabilities of foreign operations are translated to Canadian dollars at exchange rates in effect at the balance sheet date. The income and expenses of foreign operations are translated to Canadian dollars using average exchange rates for the period. The resulting unrealized gain or loss is included in other comprehensive income. The unrealized gain or loss is subsequently reclassified to profit and loss upon discontinuation of the foreign operations.

Foreign transactions

Transactions in foreign currencies not incurred by the Company's U.S. subsidiaries are translated to Canadian dollars at exchange rates in effect at the transaction dates. Foreign currency assets and liabilities are translated to Canadian dollars at exchange rates in effect at the balance sheet date and income and expenses are translated to Canadian dollars using average exchange rates for the period. Both realized and unrealized gains and losses resulting from the settlement or restatement of foreign currency transactions are included in net income.

k) Revenue Recognition

The Company's major revenue sources are comprised of sales from the production of crude oil and condensate, natural gas liquids ("NGLs") and natural gas. Revenue is recognized when control of the product transfers to the customer and the collection is reasonably probable, generally upon delivery of the product. Sales of crude oil and condensate, NGLs and natural gas production are based on variable pricing as the transaction prices are based on benchmark commodity prices and other variable factors, including quality differentials and location.

Each contract is evaluated based on the nature of the performance obligations, including the Company's role as either principal or agent. Where the Company acts as principal, revenue is recognized on a gross basis. Where the Company acts as agent, revenue is recognized on a net basis.

l) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with original maturities of three months or less.

m) Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the commencement date, the lease liability is recognized at the present value of the future lease payments and discounted using the interest rate implicit in the lease if readily determinable, or the Company's incremental borrowing rate. A corresponding right-of-use ("ROU") asset will be recognized at the amount of the lease liability, adjusted for any lease incentives received and initial direct costs incurred. Over the term of the lease, financing expense is recognized on the lease liability using the effective interest rate method and charged to net income, lease payments are applied against the lease liability and depreciation on the ROU asset is recorded by class of underlying asset.

The lease term is the non-cancellable period of a lease and includes periods covered by an optional lease extension option if reasonably certain the Company will exercise the option to extend. Leases with a term of less than 12 months or leases for underlying low value assets are recognized as an expense in net income on a straight-line basis over the lease term.

A lease modification is accounted for as a separate lease if it materially changes the scope of the lease. For a modification that is not a separate lease, on the effective date of the lease modification, the Company will remeasure the lease liability and corresponding ROU asset using the interest rate implicit in the lease or the Company's incremental borrowing rate. Any variance between the remeasured ROU asset and lease liability will be recognized as a gain or loss in net income to reflect the change in scope.

The Company may enter into transactions involving the sale of an asset, followed by an immediate lease arrangement for the same asset. Where the transfer of the asset qualifies as a sale under IFRS 15 *Revenue from Contracts with Customers*, the Company derecognizes the underlying asset, and recognizes a lease liability and corresponding ROU asset. Any gain or loss on sale is limited to the amount relating to the rights transferred to the buyer-lessor. The ROU asset is initially measured as the proportion of the previous carrying amount of the asset that relates to the ROU retained, and considers variable payments, regardless of whether they depend on an index or rate. The initial measurement of the lease liability is derived based on the initial ROU asset recognized and any gain or loss recognized at the date of the transaction. Throughout the lease term, the lease liability is reduced by the lease payments determined at the commencement date. Any difference between the actual lease payments made and the lease payments that reduce the carrying amount of the lease liability are recognized in profit or loss as variable lease payments.

The Company also acts as an intermediate lessor for office space sub-leased to other companies. The head lease between the Company and the building, and the sub-lease between the Company and tenants, are accounted for separately. As a lessor, the Company will evaluate whether a lease is a finance or operating lease. If the Company transfers substantially all the risks and rewards of ownership, the sublease is classified as a finance lease and the Company recognizes a lease receivable while derecognizing the corresponding ROU asset. If the Company retains the risks and rewards of ownership, the sublease is

classified as an operating lease, with sublease revenue recognized over the term of the sublease. The Company's current lessor arrangements are classified as operating leases and lease payments received are recognized in other income.

n) Earnings Per Share

Basic earnings per share ("EPS") is calculated by dividing the net income for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period.

Diluted EPS is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to dilutive instruments, being restricted shares issued under the Company's Restricted Share Bonus Plan and stock options under the Company's Stock Option Plan, is computed using the treasury stock method. The treasury stock method assumes that the deemed proceeds related to unrecognized share-based compensation are used to repurchase shares at the average market price during the period.

o) Government Grants

The Company may receive government grants which provide immediate financial assistance as compensation for costs or expenditures to be incurred. Government grants are accounted for when there is reasonable assurance that conditions attached to the grants are met and that the grants will be received. The Company recognizes government grants in net income on a systematic basis and in line with recognition of the expense that the grants are intended to compensate.

p) Assets Held for Sale

PP&E and E&E assets are classified as held for sale if it is highly probable their carrying amounts will be recovered through a capital disposition rather than through future operating cash flows. Before PP&E and E&E assets are classified as held for sale, they are assessed for indicators of impairment or reversal of previously recorded impairments and are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment charges or reversals are recognized in net income. Assets held for sale are classified as current assets and are not subject to DD&A. Decommissioning liabilities associated with assets held for sale are classified as current liabilities.

4. CHANGES IN ACCOUNTING POLICIES

Presentation of Financial Statements

IAS 1 *Presentation of Financial Statements* was amended in January 2020 by the International Accounting Standards Board to clarify the presentation requirements of liabilities as either current or non-current within the statement of financial position. The Company adopted this amendment in 2024 and the adoption did not have an impact on the Company's annual consolidated financial statements.

Income Taxes

IAS 12 *Income Taxes* was amended in May 2023 by the International Accounting Standards Board to provide guidance on deferred taxes arising in jurisdictions implementing the *Pillar Two model rules* published by the Organisation for Economic Co-operation and Development. This amendment was effective immediately and has been adopted by the Company with no impact to the Company's annual consolidated financial statements.

Lease Liability in a Sale and Leaseback

In September 2022, the International Accounting Standards Board issued narrow-scope amendments to IFRS 16*Leases,* which applies to sale and leaseback transactions that include variable lease payments. The amendments specify that no gain or loss can be recognized on the rights retained by the seller-lessee, and require the inclusion of variable payments that do not depend on an index or rate in the initial measurement of the ROU asset and lease liability. These amendments were effective for fiscal years beginning on or after January 1, 2024. In the current accounting period, the Company adopted the narrow-scope amendments. See Note 14 - "Leases" for additional information regarding transactions impacted by these amendments.

New accounting standards and amendments not yet adopted

Presentation and Disclosure in Financial Statements

IFRS 18 *Presentation and Disclosure in Financial Statements* was issued in April 2024 by the International Accounting Standards Board and replaces IAS 1 *Presentation of Financial Statements*. The Standard introduces a defined structure to the statements of comprehensive income and specific disclosure requirements related to the same. The Standard is required to be adopted retrospectively and is effective for fiscal years beginning on or after January 1, 2027, with early adoption permitted. The Company is evaluating the impact that this standard will have on the consolidated financial statements.

Financial Instruments* and *Financial Instruments: Disclosures

IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* were amended in May 2024 to clarify the date of recognition and derecognition of financial assets and liabilities. The amendments are effective for fiscal years beginning on or after January 1, 2026, with early adoption permitted. The Company is evaluating the impact that this amendment will have on the consolidated financial statements.

5. OTHER CURRENT ASSETS

At December 31, 2024, other current assets is comprised of deferred consideration receivable from capital dispositions of $7.2 million (December 31, 2023 - $79.2 million). See Note 8 - "Capital Acquisitions and Dispositions" for additional information.

6. OTHER LONG-TERM ASSETS

($ millions)	**2024**	2023
Deferred consideration receivable	**10.8**	—
Investment tax credits	**7.2**	7.2
Other	**0.1**	0.2
Other long-term assets	**18.1**	7.4

At December 31, 2024, deferred consideration receivable relates to deferred consideration from capital dispositions. See Note 8 - "Capital Acquisitions and Dispositions" for additional information.

7. EXPLORATION AND EVALUATION ASSETS

($ millions)	**2024**	2023 [1]
Exploration and evaluation assets at cost	**1,212.5**	1,578.6
Accumulated amortization	**(740.2)**	(971.6)
Net carrying amount	**472.3**	607.0
Reconciliation of movements during the year		
Cost, beginning of year	**1,578.6**	1,453.4
Accumulated amortization, beginning of year	**(971.6)**	(1,349.2)
Net carrying amount, beginning of year	**607.0**	104.2
Net carrying amount, beginning of year	**607.0**	104.2
Acquisitions	**15.8**	515.2
Additions	**191.8**	224.8
Dispositions	**—**	(0.1)
Reclassified as assets held for sale	**—**	(1.8)
Transfers to property, plant and equipment	**(219.7)**	(204.3)
Amortization	**(122.6)**	(30.9)
Foreign exchange	**—**	(0.1)
Net carrying amount, end of year	**472.3**	607.0

(1) Comparative period revised to reflect current period presentation.

Impairment test of exploration and evaluation assets

There were no indicators of impairment at December 31, 2024 or December 31, 2023

8. CAPITAL ACQUISITIONS AND DISPOSITIONS

In the year ended December 31, 2024, the Company incurred total transaction costs of $39.8 million that were recorded as general and administrative expenses (year ended December 31, 2023 - total transaction costs of $48.5 million, of which $39.8 million related to continuing operations).

The following table summarizes the Company's capital acquisitions and dispositions in the year ended December 31, 2024:

($ millions)	North Dakota Disposition [1]	Southern Alberta Disposition [2]	Swan Hills Disposition [3]	Non-core Saskatchewan Disposition [4]	Montney Infrastructure [5]	Other minor acquisitions and dispositions, net
Cash	(12.7)	12.1	80.5	531.6	400.0	(25.2)
Deferred consideration receivable	—	25.0	—	—	—	—
Consideration (paid) received	**(12.7)**	**37.1**	**80.5**	**531.6**	**400.0**	**(25.2)**
Working capital	—	—	—	—	—	(6.0)
Exploration and evaluation	—	—	—	—	—	15.8
Property, plant and equipment	1.6	(129.5)	(117.5)	(635.8)	(402.6)	19.3
Goodwill	—	(3.7)	(2.9)	—	—	—
Other long-term assets	—	—	—	—		(0.1)
Decommissioning liability	—	92.4	39.9	98.0	2.6	0.5
Derivative liability	—	—	3.5	—	—	—
Deferred income tax liability	—	—	—	—	—	(8.1)
Fair value of net assets acquired (Carrying value of net assets disposed)	**1.6**	**(40.8)**	**(77.0)**	**(537.8)**	**(400.0)**	**21.4**
Gain (loss) on capital dispositions	**(11.1)**	**(3.7)**	**3.5**	**(6.2)**	**—**	**(3.8)**

(1) Represents final adjustments on the transaction that closed in 2023. See Note 9 - "Discontinued Operations" for additional information.

(2) These assets were recorded as assets held for sale at December 31, 2023 and disposed on January 26, 2024.

(3) These assets were recorded as assets held for sale at December 31, 2023 and disposed on March 21, 2024.

(4) These assets were recorded as assets held for sale at March 31, 2024 and disposed on June 14, 2024. These assets were subject to impairment losses on PP&E and goodwill. For additional information, see Note 10 - "Property, Plant and Equipment" and Note 11 - "Goodwill", respectively.

(5) These assets were recorded as assets held for sale at September 30, 2024 and disposed on October 9, 2024.

On October 9, 2024, Veren closed its strategic Alberta Montney infrastructure transaction, disposing of four Company owned batteries for cash consideration of $400.0 million. Concurrent with the transaction, the Company re-negotiated certain processing and handling agreements in the Alberta Montney area to improve operational efficiencies. As part of these agreements, the Company gained operatorship of four third-party batteries and maintained operatorship of the batteries disposed. The agreements include a long-term fixed take-or-pay commitment, which has been recorded as a lease and a sale and leaseback in accordance with IFRS 16 *Leases*. See Note 14 - "Leases" for additional information.

The following table summarizes the Company's capital acquisitions and dispositions in the year ended December 31, 2023:

($ millions)	Hammerhead Acquisition [1] [2]	Kaybob Duvernay Acquisition	Alberta Montney Acquisition	North Dakota Disposition [3]	Other minor dispositions, net
Cash	(1,544.0)	(370.4)	(1,700.4)	504.6	17.3
Common shares	(493.0)	—	—	—	—
Deferred consideration receivable	—	—	—	81.2	—
Consideration (paid) received	**(2,037.0)**	**(370.4)**	**(1,700.4)**	**585.8**	**17.3**
Working capital	(116.7)	—	—	9.1	—
Derivative asset	12.3	—	—	—	—
Other long-term assets	—	—	0.1	—	—
Exploration and evaluation	354.8	52.1	108.3	(1.8)	(0.1)
Property, plant and equipment	2,406.6	323.7	1,616.6	(635.2)	(20.8)
Right-of-use asset	4.3	—	—	(1.0)	—
Goodwill	72.6	—	—	—	(0.6)
Long-term debt	(363.8)	—	—	—	—
Decommissioning liability	(9.9)	(5.4)	(24.6)	13.7	4.3
Derivative liability	(0.3)	—	—	19.0	—
Lease liability	(4.3)	—	—	1.1	—
Deferred income tax liability	(318.6)	—	—	—	—
Fair value of net assets acquired (Carrying value of net assets disposed)	**2,037.0**	**370.4**	**1,700.4**	**(595.1)**	**(17.2)**
Gain (loss) on capital dispositions	**—**	**—**	**—**	**(9.3)**	**0.1**

(1) Total net assets acquired excludes $ 696.6 million of commitments relating to transportation, $ 156.7 million related to gas processing and $ 4.8 million related to operating.

(2) Working capital includes $ 115.4 million of accounts receivable, $ 7.6 million of prepaids and deposits, and $ 239.7 million of accounts payable and accrued liabilities.

(3) Working capital includes $ 9.1 million of accounts payable and accrued liabilities.

9. DISCONTINUED OPERATIONS

In 2023, the Company disposed of its entire Northern U.S. CGU, which was comprised of producing assets in North Dakota and represented a distinct geographical area of the Company's operations. In accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations,* the results from this CGU were classified as discontinued operations. Upon disposition of the Company's U.S. operations, the cumulative foreign currency translation recognized in accumulated other comprehensive income was reclassified from shareholders' equity to profit or loss.

In the year ended December 31, 2023, the Company derecognized its U.S. tax pools as a result of the completed North Dakota asset sale.

a) Results from discontinued operations

The following table summarizes the Company's financial results from discontinued operations:

For the years ended December 31		
(Cdn$ millions)	**2024**	2023
REVENUE AND OTHER INCOME		
Oil and gas sales	**—**	612.9
Royalties	**—**	(155.9)
Oil and gas revenue	**—**	457.0
Commodity derivative losses	**—**	(23.4)
Other loss	**(11.1)**	(2.2)
	(11.1)	431.4
EXPENSES		
Operating	**—**	80.0
Transportation	**—**	12.2
General and administrative	**—**	12.7
Foreign exchange gain	**(0.5)**	(621.7)
Share-based compensation	**—**	(0.4)
Depletion, depreciation and amortization	**—**	170.3
Impairment	**—**	728.4
Accretion and financing	**—**	0.4
	(0.5)	381.9
Net income (loss) before tax from discontinued operations	**(10.6)**	49.5
Tax expense		
Current	**—**	—
Deferred	**—**	278.6
Net income (loss) from discontinued operations	**(10.6)**	(229.1)

b) Cash flows from discontinued operations

The following table summarizes cash flows from discontinued operations reported in the consolidated statements of cash flows:

For the years ended December 31		
(Cdn$ millions)	**2024**	2023
Cash provided by (used in) discontinued operations		
Operating activities	**—**	399.0
Investing activities	**(11.1)**	177.3
Increase (decrease) in cash from discontinued operations	**(11.1)**	576.3

10. PROPERTY, PLANT AND EQUIPMENT

($ millions)	2024	2023 (1)
Development and production assets	**22,172.1**	24,580.6
Corporate assets	**137.8**	132.1
Property, plant and equipment at cost	**22,309.9**	24,712.7
Accumulated depletion, depreciation and impairment	**(12,556.7)**	(13,994.4)
Net carrying amount	**9,753.2**	10,718.3
Reconciliation of movements during the year		
Development and production assets		
Cost, beginning of year	**24,580.6**	22,340.0
Accumulated depletion and impairment, beginning of year	**(13,901.4)**	(14,651.8)
Net carrying amount, beginning of year	**10,679.2**	7,688.2
Net carrying amount, beginning of year	**10,679.2**	7,688.2
Acquisitions	**21.3**	4,348.6
Additions	**1,488.4**	1,025.8
Dispositions	**0.8**	(26.9)
Transfers from exploration and evaluation assets	**219.7**	204.3
Reclassified as assets held for sale	**(1,039.6)**	(729.5)
Depletion	**(1,166.3)**	(1,009.3)
Impairment	**(486.8)**	(822.2)
Foreign exchange	**(0.1)**	0.2
Net carrying amount, end of year	**9,716.6**	10,679.2
Cost, end of year	**22,172.1**	24,580.6
Accumulated depletion and impairment, end of year	**(12,455.5)**	(13,901.4)
Net carrying amount, end of year	**9,716.6**	10,679.2
Corporate assets		
Cost, beginning of year	**132.1**	126.2
Accumulated depreciation, beginning of year	**(93.0)**	(85.0)
Net carrying amount, beginning of year	**39.1**	41.2
Net carrying amount, beginning of year	**39.1**	41.2
Additions	**5.7**	5.9
Depreciation	**(8.2)**	(8.0)
Net carrying amount, end of year	**36.6**	39.1
Cost, end of year	**137.8**	132.1
Accumulated depreciation, end of year	**(101.2)**	(93.0)
Net carrying amount, end of year	**36.6**	39.1

(1) Comparative period revised to reflect current period presentation.

At December 31, 2024, future development costs of $9.19 billion were included in costs subject to depletion (December 31, 2023 - $9.08 billion).

During the year ended December 31, 2024, the Company capitalized direct general and administrative costs of $45.1 million (year ended December 31, 2023 - $42.4 million), including $5.4 million of share-based compensation costs (year ended December 31, 2023 - $5.7 million).

Impairment test of property, plant and equipment

2024 Assets Held for Sale

At March 31, 2024, the Company classified certain non-core assets in its Southeast Saskatchewan and Southwest Saskatchewan CGUs as held for sale. Immediately prior to classifying the assets as held for sale, the Company conducted a review of the assets' recoverable amounts and recorded an impairment loss of $486.8 million on PP&E. The recoverable amount was determined based on expected consideration, which represented the assets' estimated fair value less costs of disposal. The Company completed the disposition of these assets in June 2024. See Note 8 - "Capital Acquisitions and Dispositions" for additional information.

At September 30, 2024, the Company classified certain infrastructure assets in its Alberta CGU as held for sale. Immediately prior to classifying the assets as held for sale, the Company conducted a review of the assets' recoverable amounts. The recoverable amount was determined based on expected consideration, which represented the assets' estimated fair value less costs of disposal. No impairment was recorded on PP&E. The Company completed the disposition of these assets in October 2024. See Note 8 - "Capital Acquisitions and Dispositions" for additional information.

2023 Assets Held for Sale

During the year ended December 31, 2023, certain non-core assets in the Company's Alberta CGU were classified as and remained as held for sale. The Company conducted periodic reviews of the assets' recoverable amounts and recorded a total impairment loss of $93.8 million on PP&E. The recoverable amount was determined based on expected consideration, which represented the assets' estimated fair value less costs of disposal. See Note 8 - "Capital Acquisitions and Dispositions" for additional information.

Impairment Assessment

There were no indicators of impairment or impairment reversal on remaining PP&E at December 31, 2024 or December 31, 2023.

11. GOODWILL

($ millions)	**2024**	2023
Goodwill, beginning of year	**275.9**	203.9
Hammerhead acquisition	**—**	72.6
Impairment on assets held for sale	**(25.5)**	—
Southern Alberta disposition	**(3.7)**	—
Swan Hills disposition	**(2.9)**	—
Other dispositions	**—**	(0.6)
Goodwill, end of year	**243.8**	275.9

Goodwill has been assigned to the Canadian operating segment.

Impairment test of goodwill

2024 Assets Held for Sale

At March 31, 2024, the Company classified certain non-core assets in the Canadian operating segment as held for sale. Immediately prior to classifying the assets as held for sale, the Company conducted a review of the assets' recoverable amounts and recorded an impairment loss of $25.5 million related to goodwill. The Company completed the disposition of these assets in June 2024. See Note 8 - "Capital Acquisitions and Dispositions" for additional information.

Annual Impairment Assessment

The impairment tests of goodwill compared the recoverable amount of the Company's PP&E and E&E to the carrying amount of the combined PP&E, E&E and goodwill at December 31, 2024 and December 31, 2023. The recoverable amount of the Company's PP&E and E&E was estimated using independent reserve evaluator forecast benchmark commodity prices, proved plus probable oil and gas reserve estimates and management's estimate of the fair market value of undeveloped land. As a result of these tests, the Company concluded that the estimated recoverable amounts exceeded the carrying amounts and no impairments were recorded. At December 31, 2024, the Company used an average discount rate of approximately 13 percent. With all other variables held constant, a 1 percent change in discount rate would not result in an impairment of goodwill.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of goodwill at December 31, 2024:

	2025 [1]	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035 [3]
WTI ($US/bbl) [2]	71.58	74.48	75.81	77.66	79.22	80.80	82.42	84.06	85.74	87.46	89.21
Exchange Rate ($US/$Cdn)	0.712	0.728	0.743	0.743	0.743	0.743	0.743	0.743	0.743	0.743	0.743
WTI ($Cdn/bbl)	100.53	102.31	102.03	104.52	106.62	108.75	110.93	113.14	115.40	117.71	120.07
AECO ($Cdn/mmbtu) [2]	2.36	3.33	3.48	3.69	3.76	3.83	3.91	3.99	4.07	4.15	4.23

(1) Effective January 1, 2025.

(2) The forecast benchmark commodity prices are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Benchmark commodity prices are assumed to increase by 2.0% in each year after 2035 to the end of the reserve life. Exchange rates are assumed constant at 0.743.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of goodwill at December 31, 2023:

	2024 [1]	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034 [3]
WTI ($US/bbl) [2]	73.67	74.98	76.14	77.66	79.22	80.80	82.42	84.06	85.74	87.46	89.21
Exchange Rate ($US/$Cdn)	0.752	0.752	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755	0.755
WTI ($Cdn/bbl)	97.97	99.71	100.85	102.86	104.93	107.02	109.17	111.34	113.56	115.84	118.16
AECO ($Cdn/mmbtu) [2]	2.20	3.37	4.05	4.13	4.21	4.30	4.38	4.47	4.56	4.65	4.74

(1) Effective January 1, 2024.

(2) The forecast benchmark commodity prices are adjusted for quality differentials, heat content, distance to market and other factors in performing the impairment tests.

(3) Benchmark commodity prices are assumed to increase by 2.0% in each year after 2034 to the end of the reserve life. Exchange rates are assumed constant at 0.755.

12. OTHER CURRENT LIABILITIES

($ millions)	2024	2023
Long-term compensation liability	**15.5**	37.5
Lease liability	**59.5**	40.5
Decommissioning liability	**20.0**	40.0
Other current liabilities	**95.0**	118.0

13. LONG-TERM DEBT

($ millions)	2024	2023
Revolving bank debt	**911.2**	1,932.9
Bank term loan	**—**	750.0
Public senior notes	**1,000.0**	—
Private senior notes	**543.3**	883.4
Long-term debt	**2,454.5**	3,566.3
Long-term debt due within one year	**514.4**	380.0
Long-term debt due beyond one year	**1,940.1**	3,186.3

Bank debt

Revolving bank debt

At December 31, 2024, the Company had combined facilities of $2.36 billion. This includes a $2.26 billion syndicated unsecured credit facility and a $100.0 million unsecured operating credit facility, both with a current maturity date of November 26, 2028. Both of these facilities constitute revolving credit facilities and are extendible annually.

The Company is in compliance with all debt covenants at December 31, 2024, which are listed in the table below:

Covenant Description	Maximum Ratio
Senior debt to adjusted EBITDA [1] [2]	3.50
Total debt to adjusted EBITDA [1] [3]	4.00
Total debt to capital [2] [3] [4]	0.60

(1) Adjusted EBITDA is calculated as earnings before interest, taxes, depletion, depreciation, amortization, impairment and impairment reversals, adjusted for certain non-cash items. Adjusted EBITDA is calculated on a trailing 12 month basis adjusted for material acquisitions and dispositions.

(2) Senior debt is calculated as the sum of amounts drawn on the combined facilities, outstanding letters of credit and the principal amount of the senior notes.

(3) Total debt is calculated as the sum of senior debt plus subordinated debt. Veren does not have any subordinated debt.

(4) Capital is calculated as the sum of senior debt and shareholders' equity and excludes the effect of unrealized derivative gains or losses and the adoption of IFRS 16.

The Company has a $60.0 million unsecured demand letter of credit facility. The Company had letters of credit in the amount of $3.0 million outstanding at December 31, 2024. (December 31, 2023 - $26.2 million).

Bank term loan

The Company fully retired its bank term loan during the second quarter of 2024.

Senior notes

At December 31, 2024, the Company had aggregate outstanding senior notes of $1.54 billion, as detailed below. All outstanding senior notes pay interest semi-annually, with principal due upon maturity.

Principal ($ millions)	Hedged Principal [1] (Cdn$ millions)	Unhedged Principal [2] (Cdn$ millions)	Coupon Rate	Maturity Date	Financial statement carrying value	
					2024	2023
Cdn$40.0	—	—	3.850 %	June 20, 2024	**—**	40.0
US$257.5	—	—	3.750 %	June 20, 2024	**—**	340.0
US$82.0	67.9	43.2	4.300 %	April 11, 2025	**118.1**	108.3
Cdn$65.0	65.0	—	3.940 %	April 22, 2025	**65.0**	65.0
US$230.0	262.6	32.4	4.080 %	April 22, 2025	**331.3**	303.7
US$20.0	—	28.9	4.180 %	April 22, 2027	**28.9**	26.4
Cdn$550.0	550.0	—	4.968 %	June 21, 2029	**550.0**	—
Cdn$450.0	450.0	—	5.503 %	June 21, 2034	**450.0**	—
Senior notes	1,395.5	104.5			**1,543.3**	883.4
Due within one year	395.5	75.6			**514.4**	380.0
Due beyond one year	1,000.0	28.9			**1,028.9**	503.4

(1) Represents principal amounts on US dollar private senior notes where underlying derivatives fix the Company's foreign exchange exposure or represents the Canadian dollar principal on Canadian dollar denominated senior notes.

(2) Includes the principal balance translated at the period end foreign exchange rate on US dollar private senior notes that do not have underlying cross currency swaps ("CCS").

At December 31, 2024, the Company had outstanding private senior notes of US$32.0 million and Cdn$65.0 million. Concurrent with the issuance of the U.S. denominated private senior notes, the Company entered into CCS to manage the Company's foreign exchange risk. The CCS fix the US dollar amount of certain tranches of notes, for purposes of interest and principal repayments, at a notional amount of $330.5 million. See Note 27 - "Financial Instruments and Derivatives" for additional information. The private senior notes have financial covenants similar to those of the combined credit facilities described above.

During the second quarter of 2024, the Company issued $1.00 billion of investment grade public senior notes, consisting of $550.0 million of 4.968% notes priced at par and due June 2029, and $450.0 million of 5.503% notes priced at par and due June 2034. There are no financial covenants associated with the public senior notes.

14. LEASES

Right-of-use asset

($ millions)	Office [1]	Fleet Vehicles	Equipment	Facilities	Total
Right-of-use asset at cost	129.5	41.1	38.6	497.0	706.2
Accumulated depreciation	(75.5)	(28.7)	(24.7)	(8.3)	(137.2)
Net carrying amount	54.0	12.4	13.9	488.7	569.0
Reconciliation of movements during the year					
Cost, beginning of year	124.8	36.3	37.7	—	198.8
Accumulated depreciation, beginning of year	(65.1)	(22.1)	(8.8)	—	(96.0)
Net carrying amount, beginning of year	59.7	14.2	28.9	—	102.8
Net carrying amount, beginning of year	59.7	14.2	28.9	—	102.8
Additions	3.0	4.8	1.2	497.0	506.0
Dispositions	—	—	(0.3)	—	(0.3)
Depreciation	(10.4)	(6.6)	(15.9)	(8.3)	(41.2)
Lease modification	1.7	—	—	—	1.7
Net carrying amount, end of year	54.0	12.4	13.9	488.7	569.0

(1) A portion of the Company's office space is subleased. During the year ended December 31, 2024, the Company recorded sublease income of $ 2.6 million (year ended December 31, 2023 - $ 3.7 million) as a component of other income (loss).

As part of its Montney infrastructure transaction, Veren entered into a long-term fixed take-or-pay commitment, a portion of which related to assets previously owned by the Company. In accordance with IFRS 16 *Leases* and *Lease liability in a sale and leaseback – Amendments to IFRS 16*,the Company recognized a lease liability and corresponding ROU asset, with no gain or loss recorded on the sale of the infrastructure assets. See Note 8 - "Capital Acquisitions and Dispositions" for additional information.

Lease liability

($ millions)	**2024**	2023
Lease liability, beginning of year	**144.7**	124.1
Acquisitions	**—**	4.3
Additions	**506.0**	38.2
Dispositions	**(0.3)**	—
Reclassified as liabilities associated with assets held for sale	**—**	(1.1)
Financing	**14.1**	5.2
Payments on lease liability	**(55.1)**	(26.0)
Lease modification	**1.7**	—
Lease liability, end of year	**611.1**	144.7
Expected to be incurred within one year	**59.5**	40.5
Expected to be incurred beyond one year	**551.6**	104.2

The undiscounted cash flows relating to the lease liability are as follows:

($ millions)	**December 31, 2024**
1 year	**90.0**
2 to 3 years	**145.3**
4 to 5 years	**135.9**
More than 5 years	**498.5**
Total [1]	**869.7**

(1) Includes both the principal and amounts representing financing.

15. OTHER LONG-TERM LIABILITIES

At December 31, 2024, the Company had a long-term compensation liability of $24.2 million (December 31, 2023 - $31.0 million) related to share-based compensation. See Note 25 - "Share-based Compensation" for additional information.

16. DECOMMISSIONING LIABILITY

($ millions)	2024	2023 [1]
Decommissioning liability, beginning of year	**606.4**	675.5
Liabilities incurred	**10.8**	19.8
Liabilities acquired	**0.1**	40.1
Liabilities disposed	**(0.1)**	(4.1)
Liabilities settled [2]	**(40.6)**	(45.4)
Revaluation of acquired decommissioning liabilities [3]	**0.1**	38.5
Change in estimates	**86.4**	(3.0)
Change in discount and inflation rate estimates	**0.8**	(19.6)
Accretion	**17.1**	22.7
Reclassified as liabilities associated with assets held for sale	**(101.0)**	(118.1)
Decommissioning liability, end of year	**580.0**	606.4
Expected to be incurred within one year	**20.0**	40.0
Expected to be incurred beyond one year	**560.0**	566.4

(1) Comparative period revised to reflect current period presentation.

(2) Includes nil received from government grant programs during the year ended December 31, 2024 (year ended December 31, 2023 - $ 5.4 million).

(3) Relates to the revaluation of acquired decommissioning liabilities at the period end risk-free discount rate. At the date of acquisition, decommissioning liabilities acquired are recorded at fair value based on the discount rate used on acquisition.

Management's estimate of the future decommissioning liability is based on the Company's net ownership in all wells and facilities, and considers the expected cost and timing of abandonment and reclamation activities. The Company has estimated the net present value of its total decommissioning liability to be $580.0 million at December 31, 2024 (December 31, 2023 - $606.4 million) based on total estimated undiscounted and uninflated cash outflows of $827.9 million (December 31, 2023 - $847.7 million). These obligations are expected to be settled through 2074, with the majority expected to occur after 2047. The estimated cash flows have been discounted using a risk-free rate of 3.33 percent and a derived inflation rate of 1.82 percent (December 31, 2023 - risk-free rate of 3.02 percent and inflation rate of 1.62 percent).

17. SHAREHOLDERS' CAPITAL

Veren has an unlimited number of common shares authorized for issuance.

	2024		2023	
	Number of shares	**Amount ($ millions)**	Number of shares	Amount ($ millions)
Common shares, beginning of year	**619,929,490**	**17,324.6**	550,888,983	16,675.8
Issued on capital acquisition	**—**	**—**	53,202,339	493.0
Issued for cash	**—**	**—**	48,550,000	500.1
Issued on redemption of restricted shares	**733,252**	**5.6**	1,436,017	4.9
Issued on exercise of stock options	**1,583,385**	**3.3**	464,051	0.7
Common shares repurchased for cancellation	**(10,429,500)**	**(101.1)**	(34,611,900)	(349.9)
Common shares, end of year	**611,816,627**	**17,232.4**	619,929,490	17,324.6
Cumulative share issue costs, net of tax	**—**	**(272.7)**	—	(271.9)
Total shareholders' capital, end of year	**611,816,627**	**16,959.7**	619,929,490	17,052.7

Normal Course Issuer Bids

On March 7, 2024, the Company announced the approval by the Toronto Stock Exchange of its notice to implement a Normal Course Issuer Bid ("NCIB"). The NCIB commenced on March 11, 2024 and is due to expire on March 10, 2025. The NCIB allows the Company to purchase, for cancellation, up to 61,663,522 common shares, or 10 percent of the Company's public float, as at February 29, 2024. The Company's previous NCIB commenced on March 9, 2023 and expired on March 8, 2024. Total costs paid, including commissions, fees and taxes, are recognized directly as a reduction in shareholders' equity. Under the NCIB, all common shares purchased are cancelled.

18. DEFICIT

($ millions)	2024	2023
Accumulated earnings (deficit)	**(1,857.0)**	(2,130.3)
Accumulated gain on shares issued pursuant to DRIP [1] and SDP [2]	**8.4**	8.4
Accumulated tax effect on redemption of restricted shares	**18.8**	18.2
Accumulated dividends	**(8,383.4)**	(8,098.8)
Deficit	**(10,213.2)**	(10,202.5)

(1) Premium Dividend ™ and Dividend Reinvestment Plan – suspended in 2015.

(2) Share Dividend Plan – suspended in 2015 .

19. CAPITAL MANAGEMENT

($ millions)	2024	2023
Long-term debt [1]	**2,454.5**	3,566.3
Adjusted working capital deficiency [2]	**90.9**	196.3
Unrealized foreign exchange on translation of hedged US dollar long-term debt	**(67.5)**	(24.5)
Net debt	**2,477.9**	3,738.1
Shareholders' equity	**6,761.0**	6,867.5
Total capitalization	**9,238.9**	10,605.6

(1) Includes current portion of long-term debt.

(2) Adjusted working capital deficiency is calculated as accounts payable and accrued liabilities, dividends payable and long-term compensation liability net of equity derivative contracts, less cash, accounts receivable, prepaids and deposits, and deferred consideration receivable.

The following table reconciles cash flow from operating activities to adjusted funds flow from operations for the year ended December 31, 2024 and December 31, 2023:

($ millions)	2024	2023
Cash flow from operating activities	**2,111.8**	2,195.7
Changes in non-cash working capital	**175.6**	54.9
Transaction costs	**19.8**	48.5
Decommissioning expenditures	**40.6**	40.0
Adjusted funds flow from operations	**2,347.8**	2,339.1

Veren's objective for managing its capital structure is to maintain a strong balance sheet and capital base to provide financial flexibility, position the Company to fund future development projects and provide returns to shareholders.

Veren manages its capital structure and short-term financing requirements using a measure not defined in IFRS Accounting Standards, or standardized, the ratio of net debt to adjusted funds flow from operations. Net debt to adjusted funds flow from operations is used to measure the Company's overall debt position and to measure the strength of the Company's balance sheet and may not be comparable to similar financial measures disclosed by other issuers. Veren's objective is to manage this metric to be well positioned to execute its business objectives during periods of volatile commodity prices. Veren monitors this ratio and uses it as a key measure in capital allocation decisions including capital spending levels, returns to shareholders including dividends and share repurchases, and financing considerations. The Company's net debt to adjusted funds flow from operations ratio for the trailing four quarters at December 31, 2024 was 1.1 times (December 31, 2023 - 1.6 times).

Veren is subject to certain financial covenants on its credit facilities and private senior notes agreements and was in compliance with all financial covenants as at December 31, 2024.

Veren retains financial flexibility with liquidity on its credit facilities. The Company continuously monitors the commodity price environment and manages its counterparty exposure to mitigate credit losses and protect its balance sheet.

20. COMMODITY DERIVATIVE GAINS (LOSSES)

($ millions)	2024	2023
Realized gains	**71.8**	15.5
Unrealized gains (losses)	**(86.4)**	148.3
Commodity derivative gains (losses)	**(14.6)**	163.8

21. OTHER INCOME (LOSS)

($ millions)	2024	2023
Loss on capital dispositions	**(10.2)**	(0.7)
Government grant for decommissioning expenditures	**—**	5.4
Sublease income	**2.6**	3.7
Other	**(9.4)**	5.0
Other income (loss)	**(17.0)**	13.4

22. INTEREST EXPENSE

($ millions)	2024	2023
Interest expense on long-term debt	**194.3**	126.0
Unrealized loss on interest derivative contracts	**—**	3.4
Interest expense	**194.3**	129.4

23. FOREIGN EXCHANGE GAIN

($ millions)	2024	2023
Translation of US dollar long-term debt	**(155.6)**	16.8
Realized gain on CCS - principal	**103.9**	151.8
Unrealized gain (loss) on CCS - principal	**43.5**	(155.8)
Foreign exchange gain (loss) related to US dollar long-term debt	**(8.2)**	12.8
Unrealized gain (loss) on foreign exchange swaps	**(3.2)**	2.2
Other	**17.4**	(5.0)
Foreign exchange gain	**6.0**	10.0

24. INCOME TAXES

The provision for income taxes is as follows:

($ millions)	2024	2023
Current tax recovery	**—**	(0.7)
Deferred tax expense	**59.8**	254.4
Income tax expense	**59.8**	253.7

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions, except percentages)	2024	2023 [1]
Net income before tax from continuing operations	**343.7**	1,053.1
Statutory income tax rate [2]	**24.14 %**	24.58 %
Expected provision for income taxes	**83.0**	258.9
Change in corporate tax rates and tax rate variance	**(5.4)**	(5.6)
Non-deductible capital losses (non-taxable capital gains)	**(15.4)**	0.1
Other	**(2.4)**	0.3
Income tax expense	**59.8**	253.7

(1) Comparative period revised to reflect current period presentation.

(2) The tax rate consists of the combined federal and provincial statutory tax rates for the Company for the years ended December 31, 2024 and December 31, 2023. The combined federal and provincial rate decreased from 24.58% in 2023 to 24.14% in 2024 due to changes in the provincial allocation, reflecting the increase in the Company's weighting to sales and salaries in Alberta, as compared to Saskatchewan.

The net deferred income tax liabilities are expected to be settled in the following periods:

($ millions)	2024	2023
To be settled within one year	**(1.5)**	(1.7)
To be settled beyond one year	**(708.5)**	(641.3)
Deferred income tax	**(710.0)**	(643.0)

The movement in deferred income tax assets (liabilities) are as follows:

($ millions)	At January 1, 2024	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings	**At December 31, 2024**
Deferred income tax assets:				
Decommissioning liability	146.6	—	(7.4)	**139.2**
Income tax losses carried forward	315.8	—	(99.3)	**216.5**
Risk management contracts	13.4	—	(6.1)	**7.3**
Lease liabilities	35.0	—	111.7	**146.7**
Other	53.2	0.9	(36.5)	**17.6**
	564.0	0.9	(37.6)	**527.3**
Deferred income tax liabilities:				
Property, plant and equipment	(1,127.2)	(8.1)	59.9	**(1,075.4)**
Risk management contracts	(55.0)	—	29.7	**(25.3)**
ROU asset	(24.8)	—	(111.8)	**(136.6)**
	(1,207.0)	(8.1)	(22.2)	**(1,237.3)**
Net deferred income tax liabilities	(643.0)	(7.2)	(59.8)	**(710.0)**

($ millions)	At January 1, 2023	(Charges) / credits due to acquisitions, discontinued operations & other	(Charged) / credited to earnings	At December 31, 2023
Deferred income tax assets:				
Decommissioning liability	167.4	(1.6)	(19.2)	146.6
Income tax losses carried forward	744.6	(348.2)	(80.6)	315.8
Risk management contracts	2.1	—	11.3	13.4
Lease liabilities	30.7	0.6	3.7	35.0
Other	29.9	6.8	16.5	53.2
	974.7	(342.4)	(68.3)	564.0
Deferred income tax liabilities:				
Property, plant and equipment	(743.1)	(244.2)	(139.9)	(1,127.2)
Risk management contracts	(10.8)	(2.9)	(41.3)	(55.0)
ROU asset	(19.3)	(0.6)	(4.9)	(24.8)
	(773.2)	(247.7)	(186.1)	(1,207.0)
Net deferred income tax assets (liabilities)	201.5	(590.1)	(254.4)	(643.0)

The approximate amounts of tax pools as at December 31, 2024 and December 31, 2023 are as follows:

($ millions)	**2024**	2023
Tax pools:		
Canada	**6,805.9**	8,281.0
United States [(1)]	**2,537.0**	2,319.7
Total	**9,342.9**	10,600.7

(1) The U.S. tax pools of US$1.76 billion (December 31, 2023 - US$1.76 billion) have been re-translated at the year-end foreign exchange rate.

The above tax pools include estimated Canadian non-capital losses carried forward of $902.1 million (December 31, 2023 - $1.31 billion) that expire in the years 2037 through 2043, and U.S. net operating losses of $2.54 billion (December 31, 2023 - $2.32 billion), of which $1.66 billion will expire in the years 2032 through 2037, while the remaining $881.6 million will not expire.

A deferred income tax asset has not been recognized for the U.S. tax pools of $2.54 billion (December 31, 2023 - $2.32 billion) or for other Canadian tax pools of $146.0 million (December 31, 2023 - $69.0 million) as there is not sufficient certainty regarding future utilization.

25. SHARE-BASED COMPENSATION

The following table reconciles the number of restricted shares, ESVP awards, PSUs and DSUs for the year ended December 31, 2024 and December 31, 2023:

	Restricted Shares	ESVP	PSUs [1]	DSUs
Balance, December 31, 2022	2,244,738	5,274,478	2,713,176	1,745,879
Granted	718,566	1,626,590	888,834	231,464
Redeemed	(1,436,017)	(3,721,568)	(1,627,028)	(248,920)
Forfeited	(146,602)	(519,434)	(351,734)	—
Balance, December 31, 2023	1,380,685	2,660,066	1,623,248	1,728,423
Granted	**471,732**	**1,833,916**	**1,295,268**	**223,447**
Redeemed	**(733,252)**	**(1,363,556)**	**(812,324)**	**—**
Forfeited	**—**	**(281,466)**	**—**	**—**
Balance, December 31, 2024	**1,119,165**	**2,848,960**	**2,106,192**	**1,951,870**

(1) Based on underlying units before any effect of performance multipliers.

The following table summarizes information regarding stock options outstanding as at December 31, 2024 and December 31, 2023:

	2024		2023	
	Stock options (number of units) [1]	**Weighted average exercise price ($)**	Stock options (number of units) [1]	Weighted average exercise price ($)
Balance, beginning of year	**3,224,260**	**4.74**	3,889,130	4.43
Exercised	**(2,484,622)**	**4.34**	(629,013)	2.92
Forfeited	**(25,762)**	**10.06**	(35,857)	3.43
Balance, end of year	**713,876**	**5.93**	3,224,260	4.74

(1) The Company has not granted stock options since 2021.

The following table summarizes information regarding stock options outstanding as at December 31, 2024:

Range of exercise prices ($)	Number of stock options outstanding	Weighted average remaining term for stock options outstanding (years)	Weighted average exercise price per share for stock options outstanding ($)	Number of stock options exercisable	Weighted average exercise price per share for stock options exercisable ($)
1.09 - 3.92	178,505	2.25	1.12	177,579	1.10
3.93 - 4.61	49,928	1.19	3.97	49,928	3.97
4.62 - 7.65	216,974	3.24	5.24	48,116	5.24
7.66 - 10.06	268,469	0.02	10.06	268,469	10.06
	713,876	1.64	5.93	544,092	6.15

The volume weighted average trading price of the Company's common shares on the Toronto Stock Exchange was $9.39 per share during the year ended December 31, 2024 (year ended December 31, 2023 - $9.73 per share).

For the year ended December 31, 2024, the Company calculated total share-based compensation of $19.7 million (year ended December 31, 2023 - $40.4 million), net of estimated forfeitures, of which $5.4 million was capitalized (year ended December 31, 2023 - $5.4 million).

At December 31, 2024, the current portion of long-term compensation liability of $15.5 million was included in other current liabilities (December 31, 2023 - $37.5 million) and $24.2 million was included in other long-term liabilities (December 31, 2023 - $31.0 million).

26. PER SHARE AMOUNTS

The following table summarizes the weighted average shares used in calculating net income (loss) per share:

	2024	2023
Weighted average shares – basic	**617,547,899**	545,644,234
Dilutive impact of share-based compensation [1]	**1,347,879**	2,684,473
Weighted average shares – diluted	**618,895,778**	548,328,707

(1) Excludes the impact of 72,667 weighted average shares related to share-based compensation that were anti-dilutive for the year ended December 31, 2024 (year ended December 31, 2023 - 19,186).

27. FINANCIAL INSTRUMENTS AND DERIVATIVES

The Company's financial assets and liabilities are comprised of cash, accounts receivable, deferred consideration receivable, derivative assets and liabilities, accounts payable and accrued liabilities, dividends payable and long-term debt.

Veren's derivative assets and liabilities are transacted in active markets. The Company classifies the fair value of these transactions according to the following fair value hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 - Values are based on unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date.
- Level 2 - Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace. Prices in Level 2 are either directly or indirectly observable as of the reporting date.
- Level 3 - Values are based on prices or valuation techniques that are not based on observable market data.

Accordingly, Veren's derivative assets and liabilities are classified as Level 2. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

Discussions of the fair values and risks associated with financial assets and liabilities, as well as summarized information related to derivative positions are detailed below:

a) Carrying amount and fair value of financial instruments

The fair value of cash, accounts receivable, accounts payable and accrued liabilities and dividends payable approximate their carrying amount due to the short-term nature of those instruments. The fair value of the amounts drawn on bank debt is equal to its carrying amount as the facilities bear interest at floating rates and credit spreads that are indicative of market rates. These financial instruments are classified as financial assets and liabilities at amortized cost and are reported at amortized cost.

A portion of the deferred consideration receivable is short-term in nature and its fair value approximates its carrying value. The remaining portion of the deferred consideration receivable bears interest. Both receivables are classified as financial assets at amortized cost and reported at amortized cost.

Veren's derivative assets and liabilities are transacted in active markets, classified as financial assets and liabilities at fair value through profit or loss and fair valued at each period with the resulting gain or loss recorded in net income.

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair values as at December 31, 2024:

($ millions)	Carrying Value	Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Financial assets					
Derivatives	184.7	184.7	—	184.7	—
	184.7	184.7	—	184.7	—
Financial liabilities					
Derivatives	30.5	30.5	—	30.5	—
Senior notes [(1)]	1,543.3	1,580.8	—	1,580.8	—
	1,573.8	1,611.3	—	1,611.3	—

(1) The senior notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian dollars at the period end exchange rate. The fair value of the notes is calculated based on current interest rates and is not recorded in the financial statements.

The following table summarizes the carrying value of the Company's remaining financial assets and liabilities as compared to their respective fair values as at December 31, 2023:

($ millions)	Carrying Value	Fair Value	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Financial assets					
Derivatives	255.0	255.0	—	255.0	—
	255.0	255.0	—	255.0	—
Financial liabilities					
Derivatives	55.2	55.2	—	55.2	—
Senior notes [1]	883.4	853.0	—	853.0	—
	938.6	908.2	—	908.2	—

(1) The senior notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian dollars at the period end exchange rate. The fair value of the notes is calculated based on interest rates at December 31, 2023, and is not recorded in the financial statements.

Derivative assets and liabilities

Derivative assets and liabilities arise from the use of derivative contracts. Veren's derivative assets and liabilities are classified as Level 2 with values based on inputs including quoted forward prices for commodities, time value and volatility factors. Accordingly, the Company's derivative financial instruments are classified as fair value through profit or loss and are reported at fair value with changes in fair value recorded in net income.

The following table summarizes the fair value as at December 31, 2024 and the change in fair value for the year ended December 31, 2024:

($ millions)	Commodity [1]	Interest [2]	Foreign exchange [3]	Equity	Total
Derivative assets, beginning of year	173.5	3.3	21.4	1.6	199.8
Dispositions	3.5	—	—	—	3.5
Unrealized change in fair value	(86.4)	—	40.3	(9.3)	(55.4)
Foreign exchange	6.3	—	—	—	6.3
Derivative assets (liabilities), end of year	96.9	3.3	61.7	(7.7)	154.2
Derivative assets, end of year	118.9	3.3	62.5	—	184.7
Derivative liabilities, end of year	(22.0)	—	(0.8)	(7.7)	(30.5)

(1) Includes crude oil, crude oil differentials, natural gas and natural gas differential contracts.

(2) Interest payments on CCS.

(3) Includes principal portion of CCS and foreign exchange contracts.

The following table summarizes the fair value as at December 31, 2023 and the change in fair value for the year ended December 31, 2023:

($ millions)	Commodity [1]	Interest [2]	Foreign exchange [3]	Equity	Total
Derivative assets, beginning of year	14.0	6.7	175.0	30.9	226.6
Acquisitions	12.0	—	—	—	12.0
Dispositions	19.0	—	—	—	19.0
Unrealized change in fair value	129.4	(3.4)	(153.6)	(29.3)	(56.9)
Foreign exchange	(0.9)	—	—	—	(0.9)
Derivative assets, end of year	173.5	3.3	21.4	1.6	199.8
Derivative assets, end of year	176.5	3.3	72.2	3.0	255.0
Derivative liabilities, end of year	(3.0)	—	(50.8)	(1.4)	(55.2)

(1) Includes crude oil, crude oil differentials, natural gas and natural gas differential contracts.

(2) Interest payments on CCS.

(3) Includes principal portion of CCS and foreign exchange contracts.

Offsetting financial assets and liabilities

Financial assets and liabilities are only offset if the Company has the legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. The Company offsets derivative assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. The following table summarizes the gross asset and liability positions of the Company's financial derivatives by contract that are offset on the balance sheet as at December 31, 2024 and December 31, 2023:

	2024			2023		
($ millions)	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Gross amount	**193.8**	**(39.6)**	**154.2**	258.4	(58.6)	199.8
Amount offset	**(9.1)**	**9.1**	**—**	(3.4)	3.4	—
Net amount	**184.7**	**(30.5)**	**154.2**	255.0	(55.2)	199.8

b) Risks associated with financial assets and liabilities

The Company is exposed to financial risks from its financial assets and liabilities. The financial risks include market risk relating to commodity prices, interest rates, foreign exchange rates and equity price as well as credit and liquidity risk.

Commodity price risk

The Company is exposed to commodity price risk on crude oil and condensate, NGLs and natural gas revenues. To manage a portion of this risk, the Company has entered into various derivative agreements.

The following table summarizes the unrealized gains (losses) on the Company's commodity financial derivative contracts and the resulting impact on income before tax due to fluctuations in commodity prices or differentials, with all other variables held constant:

($ millions)	**2024**		2023	
	Increase 10%	**Decrease 10%**	Increase 10%	Decrease 10%
Commodity price				
Crude oil	**(118.4)**	**95.4**	(134.4)	135.5
Natural gas	**(38.5)**	**38.6**	(25.4)	25.8
Differential				
Crude oil	**1.8**	**(1.8)**	—	—
Natural gas	**27.9**	**(27.9)**	15.5	(15.5)

Interest rate risk

The Company is exposed to interest rate risk on amounts drawn on its bank credit facilities. Based on drawn bank debt at December 31, 2024, a percent increase or decrease in the interest rate would amount to an impact on income before tax of $9.1 million on an annualized basis (December 31, 2023 - $26.8 million).

Foreign exchange risk

The Company is exposed to foreign exchange risk in relation to its US dollar denominated long-term debt, US dollar denominated working capital, US dollar denominated commodity derivative contracts and on a portion of its commodity sales. Veren utilizes foreign exchange derivatives to hedge its foreign exchange exposure on its US dollar denominated long-term debt. To reduce foreign exchange risk relating to commodity sales, the Company utilizes a combination of foreign exchange swaps and fixed price WTI crude oil contracts that settle in Canadian dollars.

The following table summarizes the resulting unrealized gains (losses) impacting income before tax due to the respective changes in the period end and applicable foreign exchange rates, with all other variables held constant:

($ millions)		**2024**		2023	
Cdn$ relative to US$	Exchange Rate	**Increase 10%**	**Decrease 10%**	Increase 10%	Decrease 10%
US dollar long-term debt	Period End	**128.5**	**(128.5)**	265.1	(265.1)
Cross currency swaps	Forward	**(118.2)**	**118.2**	(254.8)	254.8
Foreign exchange swaps	Forward	**8.5**	**(8.5)**	14.1	(14.1)

Equity price risk

The Company is exposed to equity price risk on its own share price in relation to certain share-based compensation plans detailed in Note 25 - "Share-based Compensation". The Company has entered into total return swaps to mitigate its exposure to fluctuations in its share price by fixing the future settlement cost on a portion of its cash settled plans.

The following table summarizes the unrealized gains (losses) on the Company's equity derivative contracts and the resulting impact on income before tax due to the respective changes in the applicable share price, with all other variables held constant:

($ millions)	**2024**		2023 [1]	
Share price	**Increase 25%**	**Decrease 25%**	Increase 25%	Decrease 25%
Total return swaps	**4.7**	**(4.7)**	6.3	(6.3)

(1) Comparative period revised to reflect current period presentation.

Credit risk

The Company is exposed to credit risk in relation to its physical oil and gas sales, financial counterparty, deferred consideration and joint venture receivables. A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. To mitigate credit risk associated with its physical sales portfolio, Veren obtains financial assurances such as parental guarantees, letters of credit, prepayments and third-party credit insurance. Including these assurances, approximately 98 percent of the Company's oil and gas sales are with entities considered investment grade.

At December 31, 2024, approximately 4 percent (December 31, 2023 - 4 percent) of the Company's accounts receivable balance was outstanding for more than 90 days and the Company's average expected credit loss was 0.84 percent (December 31, 2023 - 0.83 percent) on a portion of the Company's accounts receivable balance relating to joint venture receivables.

Liquidity risk

The Company manages its liquidity risk through managing its capital structure and continuously monitoring forecast cash flows and available credit under existing banking facilities as well as other potential sources of capital.

At December 31, 2024, the Company had available unused borrowing capacity on bank credit facilities of approximately $.45 billion, including cash of $17.1 million.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2024, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Accounts payable and accrued liabilities	493.5	—	—	—	493.5
Dividends payable	70.7	—	—	—	70.7
Derivative liabilities [1]	7.2	8.0	—	—	15.2
Senior notes [2]	534.0	134.8	640.5	561.4	1,870.7
Bank debt [3]	59.7	113.2	971.5	—	1,144.4

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS related to the senior notes, which fix the amounts due in Canadian dollars. US dollar senior notes that do not have any underlying CCS are translated at the period end foreign exchange rate.

(3) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2024, and includes undiscounted cash outflows pursuant to the CCS related to Secured Overnight Financing Rate ("SOFR") loans.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2023, is outlined in the table below:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Accounts payable and accrued liabilities	634.9	—	—	—	634.9
Dividends payable	56.8	—	—	—	56.8
Derivative liabilities [1]	—	3.2	—	—	3.2
Senior notes [2]	342.8	476.5	27.0	—	846.3
Bank debt [3]	236.3	3,118.8	—	—	3,355.1

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCS related to the senior notes, which fix the amounts due in Canadian dollars. US dollar senior notes that do not have any underlying CCS are translated at the period end foreign exchange rate.

(3) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2023, and includes undiscounted cash outflows pursuant to the CCS related to SOFR loans.

c) Derivative contracts

The following is a summary of derivative contracts in place as at December 31, 2024:

WTI Crude Oil Derivative Contracts – Canadian Dollar [1]					
	Swap		Collar		
Term	Volume (bbls/d)	Average Price ($/bbl)	Volumes (bbls/d)	Average Sold Call Price ($/bbl)	Average Bought Put Price ($/bbl)
January 2025 - December 2025 [2]	23,601	99.44	8,578	106.04	96.04

(1) Volumes and prices reported are the weighted average volumes and prices for the period.

(2) Includes 3,000 bbls/d which can be extended at the option of the counterparty for the second half of 2025 at an average swap price of $ 102.27/bbl and 5,000 bbls/d which can be extended at the option of the counterparty for the first half of 2026 at an average swap price of $100.36/bbl.

WTI Crude Oil Differential Derivative Contracts – US Dollar [1]				
Term	Volume (bbls/d)	Contract	Basis	Fixed Differential (US$/bbl)
January 2025 - March 2025	15,000	Basis Swap	MSW [2]	(3.19)
January 2025 - March 2025	5,000	Basis Swap	WCS [3]	(14.34)
January 2025 - March 2025	5,000	Basis Swap	C5+ [4]	1.61

(1) Volumes and prices reported are the weighted average volumes and prices for the period.

(2) MSW refers to the Mixed Sweet Blend crude oil differential.

(3) WCS refers to the Western Canadian Select crude oil differential.

(4) C5+ refers to the C5+ condensate crude oil differential.

NYMEX Natural Gas Derivative Contracts – US Dollar [1]					
	Swap		Collar		
Term	Volume (mmbtu/d)	Average Price (US$/mmbtu)	Volume (mmbtu/d)	Average Sold Call Price (US$/mmbtu)	Average Bought Put Price (US$/mmbtu)
January 2025 - December 2025	69,836	3.49	65,000	3.92	3.32
January 2026 - December 2026	56,164	3.71	35,000	4.06	3.66

(1) Volumes and prices reported are the weighted average volumes and prices for the period.

NYMEX Natural Gas Differential Derivative Contracts – US Dollar [1]				
Term	Volume (mmbtu/d)	Contract	Basis	Fixed Differential (US$/mmbtu)
January 2025 - December 2025	193,000	Basis Swap	AECO	(1.11)
January 2026 - December 2026	91,164	Basis Swap	AECO	(1.36)

(1) Volumes and prices reported are the weighted average volumes and prices for the period.

Cross Currency Derivative Contracts					
Term	Contract	Receive Notional Principal (US$ millions)	Fixed Rate (US%)	Pay Notional Principal (Cdn$ millions)	Fixed Rate (Cdn%)
January 2025	Swap	280.0	6.35	391.1	5.17
January 2025 - February 2025	Swap	280.0	6.32	391.0	5.10
January 2025 - April 2025	Swap	52.0	4.30	67.9	3.98
January 2025 - April 2025	Swap	207.5	4.08	262.6	4.13

Foreign Exchange Forward Derivative Contracts					
Settlement Date	Contract	Receive Currency	Receive Notional Principal ($ millions)	Pay Currency	Pay Notional Principal ($ millions)
January 2025	Swap [1]	Cdn$	84.0	US$	59.0

(1) Based on an average floating exchange rate.

Equity Derivative Contracts Term	Contract	Notional Principal ($ millions)	Number of shares
January 2025 - March 2025	Swap	17.1	1,676,910
January 2025 - March 2026	Swap	9.3	855,519

28. RELATED PARTY TRANSACTIONS

Compensation of key management personnel

Key management personnel of the Company consists of its directors and executive officers. For the year ended December 31, 2024, the compensation recorded as short-term benefits relating to key management personnel was $6.7 million (year ended December 31, 2023 - $7.3 million). Short-term benefits include salaries and directors' fees, annual bonuses and other benefits. In addition, the Company provides share-based compensation under its RSU, PSU, DSU and stock option plans. For the year ended December 31, 2024, share-based compensation costs relating to key management personnel was $3.2 million (year ended December 31, 2023 - $19.4 million).

29. COMMITMENTS

At December 31, 2024, the Company had contractual obligations and commitments as follows:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Operating [(1)]	16.1	20.9	10.4	2.6	50.0
Gas processing	87.5	174.0	143.4	469.3	874.2
Transportation	253.2	391.6	373.1	507.8	1,525.7
Total contractual commitments [(2)]	356.8	586.5	526.9	979.7	2,449.9

(1) Includes operating costs on the Company's office space, net of $ 17.2 million recoveries from subleases.

(2) Excludes contracts accounted for under IFRS 16 *Leases*. See Note 14 - "Leases" for additional information.

30. SUPPLEMENTAL DISCLOSURES

Comprehensive income statement presentation

The Company's statements of comprehensive income are prepared primarily by nature of expense, with the exception of compensation expenses which are included in the operating, general and administrative and share-based compensation line items, as follows:

($ millions)	**2024**	2023
Operating	**74.0**	64.0
General and administrative	**66.0**	66.8
Share-based compensation [(1)]	**9.8**	9.4
Total compensation expenses	**149.8**	140.2

(1) Excludes unrealized loss on equity derivative contracts of $ 9.3 million for the year ended December 31, 2024 (year ended December 31, 2023 - $ 29.3 million).

Cash flow statement presentation

($ millions)	**2024**	2023
Operating activities		
Changes in non-cash working capital:		
Accounts receivable	**(7.3)**	66.7
Prepaids and deposits	**2.7**	(2.2)
Accounts payable and accrued liabilities	**(142.3)**	(97.8)
Other current liabilities	**(21.9)**	(11.8)
Other long-term liabilities	**(6.8)**	(9.8)
	(175.6)	(54.9)
Investing activities		
Changes in non-cash working capital:		
Accounts receivable	**(1.1)**	—
Other current assets	**72.0**	(60.5)
Accounts payable and accrued liabilities	**(8.5)**	56.3
	62.4	(4.2)
Financing activities		
Changes in non-cash working capital:		
Prepaids and deposits	**(13.9)**	(12.6)
Accounts payable and accrued liabilities	**3.0**	(2.0)
Dividends payable	**13.9**	(42.6)
	3.0	(57.2)

Supplementary financing cash flow information

The Company's reconciliation of cash flow from financing activities is outlined in the table below:

($ millions)	Dividends payable	Long-term debt [1]	Lease liability [2]
December 31, 2022	99.4	1,441.5	124.1
Changes from cash flow from financing activities:			
Increase in bank debt, net		2,675.1	
Repayment of senior notes and acquired long-term debt		(897.9)	
Realized gain on cross currency swap maturity		147.7	
Dividends paid	(254.5)		
Payments on principal portion of lease liability			(20.8)
Non-cash changes:			
Dividends declared	211.9		
Acquisitions		363.8	4.3
Additions			38.2
Dispositions			(1.1)
Foreign exchange		(163.9)	
December 31, 2023	56.8	3,566.3	144.7
Changes from cash flow from financing activities:			
Decrease in bank debt, net		**(1,874.3)**	
Issuance of senior notes		**1,000.0**	
Repayment of senior notes and acquired long-term debt		**(392.9)**	
Realized gain on cross currency swap maturity		**103.9**	
Dividends paid	**(270.7)**		
Payments on principal portion of lease liability			**(41.0)**
Non-cash changes:			
Dividends declared	**284.6**		
Additions			**506.0**
Dispositions			**(0.3)**
Lease modification			**1.7**
Foreign exchange		**51.5**	
December 31, 2024	**70.7**	**2,454.5**	**611.1**

(1) Includes current portion of long-term debt.

(2) Includes current portion of lease liability.

31. OIL AND GAS SALES

The following table reconciles oil and gas sales by country:

($ millions) [1]	**2024**	2023
Canada		
Crude oil and condensate sales	**3,741.9**	3,082.5
NGL sales	**235.6**	180.2
Natural gas sales [2]	**293.8**	236.3
Total Canada	**4,271.3**	3,499.0
U.S.		
Crude oil and condensate sales	**—**	569.6
NGL sales	**—**	27.0
Natural gas sales	**—**	16.3
Total U.S. [3]	**—**	612.9
Total oil and gas sales	**4,271.3**	4,111.9

(1) Oil and gas sales are reported before realized derivatives.

(2) During the year ended December 31, 2024, natural gas sales include $ 52.6 million related to Canadian production sold into U.S. pricing markets through the Company's U.S. legal entity (year ended December 31, 2023 - $7.4 million).

(3) Discontinued operations.

Directors

Barbara Munroe, Chair [6]

Corey Bieber [1] [5]

James Craddock [2] [3] [5]

John Dielwart [3] [4]

Mike Jackson [1] [5]

Jennifer Koury [2] [5]

Jodi Jenson Labrie [1] [2]

François Langlois [1] [3] [4]

Myron Stadnyk [1] [2] [4]

Mindy Wight [2]

Craig Bryksa [4]

[1] Member of the Audit Committee of the Board of Directors

[2] Member of the Human Resources and Compensation Committee of the Board of Directors

[3] Member of the Reserves Committee of the Board of Directors

[4] Member of the Environment, Safety and Sustainability Committee of the Board of Directors

[5] Member of the Corporate Governance and Nominating Committee

[6] Chair of the Board serves in an *ex officio* capacity on each Committee

Officers

Craig Bryksa
President and Chief Executive Officer

Ken Lamont
Chief Financial Officer

Ryan Gritzfeldt
Chief Operating Officer

Mark Eade
Senior Vice President, General Counsel and Corporate Secretary

Justin Foraie
Senior Vice President, Operations and Marketing

Garret Holt
Senior Vice President, Strategy and Planning

Michael Politeski
Senior Vice President, Finance and Treasurer

Shelly Witwer
Senior Vice President, Business Development

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Banker

The Bank of Nova Scotia
Calgary, Alberta

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

Norton Rose Fulbright Canada LLP
Calgary, Alberta

Evaluation Engineers

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Registrar and Transfer Agent

Investors are encouraged to contact Veren's Registrar and Transfer Agent for information regarding their security holdings:

Computershare Trust Company of Canada
600, 530 - 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Tel: (403) 267-6800

Stock Exchanges

Toronto Stock Exchange - TSX
New York Stock Exchange - NYSE

Stock Symbol

VRN

Investor Contacts

Sarfraz Somani
Manager, Investor Relations
(403) 693-0020

Exhibit 99.3

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is dated February 26, 2025 and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2024 for a full understanding of the financial position and results of operations of Veren Inc. (the "Company" or "Veren"). Except as otherwise noted, the results of operations present only continuing operations.

The audited consolidated financial statements and comparative information for the year ended December 31, 2024 are presented under IFRS Accounting Standards as issued by the International Accounting Standards Board.

Structure of the Business

On May 10, 2024, Crescent Point Energy Corp. changed its name to Veren Inc. The principal undertaking of Veren and its subsidiaries is to carry on the business of acquiring, developing and holding interests in petroleum and natural gas properties. Amounts in this MD&A are in Canadian dollars unless noted otherwise. References to "US$" and "US dollars" are to United States ("U.S.") dollars.

Overview

The Company reported adjusted funds flow from operations of $2.35 billion, net income of $273.3 million, adjusted net earnings from operations of $848.8 million and excess cash flow of $641.6 million for the year ended December 31, 2024. The Company continued to execute on its return of capital framework by returning $385.7 million to shareholders in 2024 through its base dividend and share repurchases.

In 2024, Veren had average annual production of 191,163boe/d (guidance of 191,000 boe/d), annual operating expenses of $13.46/boe (guidance of $13.50/boe) and development capital expenditures of $1.51 billion (guidance of $1.45 - $1.50 billion) to drill 180 (165.8 net) wells.

The Company executed on a number of strategic transactions in 2024, which allowed for increased operational efficiencies and concentrated development of the Alberta Montney and Kaybob Duvernay assets. In the first quarter of 2024, Veren completed the disposition of its Southern Alberta and Swan Hills assets for total consideration of $37.1 million and $80.5 million, respectively. On June 14, 2024, the Company completed the disposition of certain non-core assets in its Southeast Saskatchewan and Southwest Saskatchewan cash-generating units ("CGUs") for total consideration of $531.6 million. The Company closed its Alberta Montney infrastructure transaction on October 9, 2024 for cash proceeds of $400.0 million. The net proceeds from these transactions were used to repay indebtedness.

Veren received an investment-grade credit rating and subsequently closed an aggregate $1.00 billion public senior note offering during the second quarter of 2024. The proceeds received from this offering were used to repay bank debt, including retiring the Company's bank term loan. The Company reduced its net debt by $1.26 billion during the year ended December 31, 2024, reflecting a reduction of approximately 35 percent, exiting the year with net debt of $2.48 billion or 1.1 times net debt to adjusted funds flow from operations.

To protect against commodity price volatility, the Company continues to hedge a portion of its production. Veren has hedged approximately 35 percent of its oil and liquids production and approximately 35 percent of its natural gas production in 2025, net of royalty interest.

Veren's 2025 guidance includes average production of 188,000 - 196,000 boe/d, development capital expenditures of $1.48 - $1.58 billion and operating expenses of $12.75 - $13.75/boe. Based on the current forecast commodity prices and the Company's 2025 hedge book, the Company expects to generate strong returns and excess cash flow to provide continued returns to shareholders.

Adjusted funds flow from operations, adjusted net earnings from operations, excess cash flow, total return of capital, base dividends, development capital expenditures, net debt and net debt to adjusted funds flow from operations are specified financial measures that do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Results of Operations

Production

	2024	2023	% Change
Crude oil and condensate (bbls/d)	**107,541**	88,087	22
NGLs (bbls/d)	**17,533**	15,026	17
Natural gas (mcf/d)	**396,534**	211,275	88
Production from continuing operations (boe/d)	**191,163**	138,326	38
Production from discontinued operations (boe/d)	**—**	21,085	(100)
Total average daily production (boe/d)	**191,163**	159,411	20
Crude oil and liquids - continuing operations (%)	**65**	75	(10)
Natural gas - continuing operations (%)	**35**	25	10
Total (%)	**100**	100	—

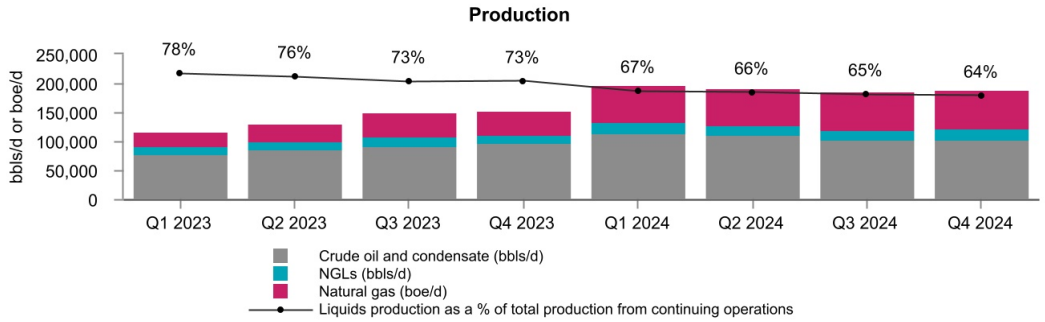
The following is a summary of Veren's production by area:

Production By Area (boe/d)	2024	2023	% Change
Alberta	**140,037**	75,792	85
Saskatchewan	**51,126**	62,534	(18)
Production from continuing operations	**191,163**	138,326	38
Production from discontinued operations - North Dakota	**—**	21,085	(100)
Total average daily production	**191,163**	159,411	20

Production from continuing operations averaged 191,163 boe/d durirg 2024 compared to 138,326 boe/d in 2023. The increase of 38 percent is primarily due to the acquisitions of the Alberta Montney assets in May 2023 and December 2023, along with organic growth from the Company's Alberta development program. This was partially offset by the disposition of non-core assets in the first half of 2024.

The Company's crude oil and liquids weighting decreased by 10 percent year over year. The decrease was mainly due to the increased production from the Alberta Montney assets mentioned above, which have a higher proportion of natural gas production, and the disposition of oil-weighted assets in the first half of 2024.

Exhibit 1



Marketing and Prices

Average Selling Prices [1]	2024	2023	% Change
Crude oil and condensate ($/bbl)	**95.07**	95.87	(1)
NGLs ($/bbl)	**36.71**	32.86	12
Natural gas ($/mcf)	**2.02**	3.06	(34)
Total ($/boe)	**61.05**	69.30	(12)

(1) The average selling prices reported are before realized commodity derivatives and transportation.

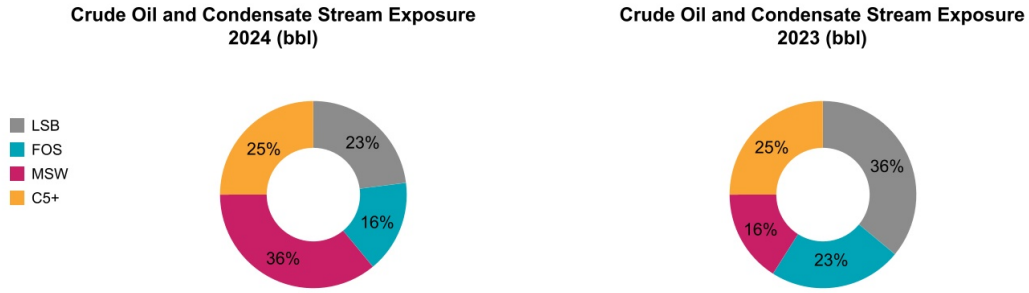
Benchmark Pricing	2024	2023	% Change
Crude Oil Prices			
WTI crude oil (US$/bbl) [1]	**75.72**	77.61	(2)
WTI crude oil (Cdn$/bbl)	**103.73**	104.74	(1)
Crude Oil and Condensate Differentials			
LSB crude oil (Cdn$/bbl) [2]	**(8.18)**	(6.79)	20
FOS crude oil (Cdn$/bbl) [3]	**(18.66)**	(23.39)	(20)
MSW crude oil (Cdn$/bbl) [4]	**(5.77)**	(3.64)	59
C5+ condensate (Cdn$/bbl) [5]	**(3.81)**	(1.44)	165
Natural Gas Prices			
AECO daily spot natural gas (Cdn$/mcf) [6]	**1.46**	2.64	(45)
AECO monthly index natural gas (Cdn$/mcf)	**1.43**	2.92	(51)
NYMEX natural gas (US$/mmbtu) [7]	**2.27**	2.74	(17)
Dawn natural gas (US$/mmbtu) [8]	**1.82**	2.16	(16)
Chicago natural gas (US$/mmbtu) [9]	**1.97**	2.11	(7)
Foreign Exchange Rate			
Exchange rate (US$/Cdn$)	**0.730**	0.741	(1)

(1) WTI refers to the West Texas Intermediate crude oil price.
(2) LSB refers to the Light Sour Blend crude oil price.
(3) FOS refers to the Fosterton crude oil price, which typically receives a premium to the Western Canadian Select ("WCS") price.
(4) MSW refers to Mixed Sweet Blend crude oil price.
(5) C5+ condensate refers to the Canadian C5+ condensate index.
(6) AECO refers to the Alberta Energy Company natural gas price.
(7) NYMEX refers to the New York Mercantile Exchange natural gas price.
(8) Dawn refers to the Dawn Ontario natural gas price.
(9) Chicago refers to the Chicago City-Gate natural gas price.

Benchmark crude oil prices weakened slightly in 2024 compared to 2023, primarily due to global demand concerns driven by weaker economic and demand growth outlooks in China, coupled with an increase in crude oil supply from non-OPEC+ producers. This was partially offset by sustained OPEC+ voluntary production cuts.

Natural gas prices were significantly weaker in 2024 compared to 2023. Mild weather conditions across most of North America led to a decrease in gas consumption during the typical peak demand season. As a result, inventory storage levels exceeded the 5-year average, while higher production from the U.S. and Canada placed further downward pressure on natural gas prices. The AECO daily and NYMEX benchmark prices decreased 45 percent and 17 percent in 2024, respectively, compared to 2023. The AECO daily benchmark price experienced a sharper decline in 2024 relative to the NYMEX benchmark price, primarily due to an over-supplied Alberta market and downstream pipeline maintenance, which restricted production sales from Alberta and led to increased injection and storage levels.

Exhibit 2



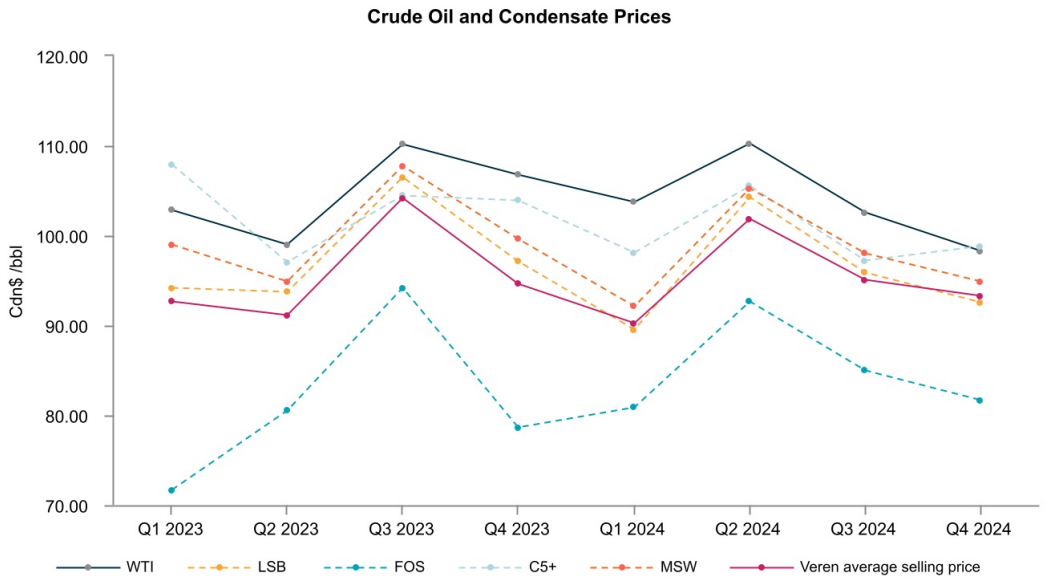
LSB and MSW crude oil differentials weakened in 2024 compared to 2023, primarily due to a rise in crude oil supply in the Western Canadian Sedimentary Basin, constrained takeaway capacity and unplanned refinery outages. This was partially offset by the startup of the Trans Mountain pipeline ("TMX") expansion in May 2024, which increased pipeline capacity and access to Asian markets. FOS crude oil differentials strengthened in 2024 compared to 2023, primarily due to narrower WCS differentials as a result of the TMX expansion. Condensate differentials weakened in 2024 compared to 2023, largely due to an oversupplied North American condensate market and elevated storage levels.

Despite significant widening of the benchmark oil and condensate differentials relative to WTI, the Company's realized pricing differential remained generally consistent year over year. The slight tightening in the Company's realized crude oil and condensate differential from $8.87 per bbl in 2023 to $8.66 per bbl in 2024 was primarily due to an increase in the proportion of liquids sold on higher quality benchmarks as a result of the Alberta Montney acquisitions.

In 2024, the Company's average selling price for NGLs increased 12 percent, primarily due to higher propane prices related to increased U.S. exports, lower inventory levels and the sale of a portion of the Company's propane production at Far East Index pricing, which receives a premium relative to the Edmonton propane market.

The Company's average selling price for natural gas decreased 34 percent in 2024 compared to 2023, primarily as a result of weaker AECO daily and NYMEX benchmark prices. Veren's average selling price experienced a smaller decline relative to the AECO daily benchmark price, primarily due to the Company's physical gas diversification into markets outside Alberta, such as Dawn and Chicago.

Exhibit 3



Commodity Derivatives

Management of cash flow variability is an integral component of Veren's business strategy. Veren regularly monitors changing business and market conditions while executing its strategic risk management program. Veren proactively manages the risk exposure inherent in movements in the price of crude oil, natural gas, interest rates, the Company's share price and the US/Cdn dollar exchange rate using derivatives with investment-grade counterparties.

The Company's crude oil derivatives are referenced to WTI, MSW, WCS and C5+ condensate. The Company's natural gas derivatives are referenced to NYMEX and the AECO monthly index. Veren utilizes a variety of derivatives, including swaps, swaptions, collars and put options, to protect against downward commodity price movements while also providing the opportunity for some upside participation during periods of rising prices. This reduces the volatility of the selling price of crude oil, NGLs, condensate and natural gas production and provides a measure of stability to the Company's cash flow. See Note 27 - "Financial Instruments and Derivatives" in the audited consolidated financial statements for the year ended December 31, 2024, for additional information on the Company's derivatives.

The following is a summary of the realized commodity derivative gains (losses):

($ millions, except volume amounts)	**2024**	2023	% Change
Average crude oil volumes hedged (bbls/d) [1]	**54,700**	28,955	89
Crude oil realized derivative loss [1]	**(6.0)**	(3.3)	82
per bbl - continuing operations	**(0.15)**	(0.10)	50
Average natural gas volumes hedged (GJ/d) [2] [3]	**122,208**	40,325	203
Natural gas realized derivative gain [3]	**77.8**	18.8	314
per mcf - continuing operations	**0.54**	0.24	125
Average barrels of oil equivalent hedged (boe/d) [1] [3]	**74,006**	35,325	110
Total realized commodity derivative gains [1] [3]	**71.8**	15.5	363
per boe - continuing operations	**1.03**	0.31	232
per boe - total average daily production	**1.03**	0.27	281

(1) The crude oil realized derivative loss for the years ended December 31, 2024 and December 31, 2023 includes the realized derivative gains and losses on financial crude oil price differential contracts. The average crude oil volumes hedged and average barrels of oil equivalent hedged do not include the hedged volumes related to financial crude oil price differential contracts.

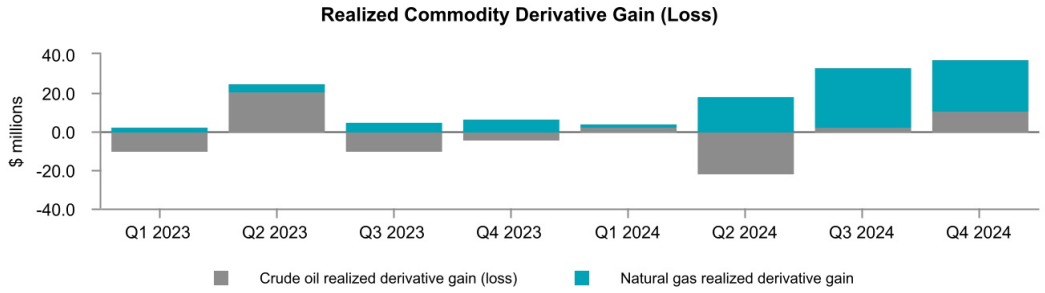
(2) GJ/d is defined as gigajoules per day.

(3) The natural gas realized derivative gain for the years ended December 31, 2024 and December 31, 2023 includes the realized derivative gains and losses on financial natural gas price differential contracts. The average natural gas volumes hedged and average barrels of oil equivalent hedged do not include the hedged volumes related to financial natural gas price differentials contracts.

For the year ended December 31, 2024, the Company's realized derivative loss on crude oil contracts was $6.0 million. The realized derivative loss was primarily attributable to higher Cdn$ WTI benchmark pricing compared to the Company's average hedge price.

The Company's realized derivative gain on natural gas contracts was $77.8 million for the year ended December 31, 2024. The realized derivative gain was primarily due to lower average NYMEX and AECO monthly index prices compared to the Company's average hedge price. Wider AECO to NYMEX differentials in 2024 also resulted in gains on the Company's natural gas differential contracts.

Exhibit 4



The following is a summary of the Company's unrealized commodity derivative gains (losses):

($ millions)	**2024**	2023	% Change
Crude oil	**(138.0)**	127.4	(208)
Natural gas	**51.6**	20.9	147
Total unrealized commodity derivative gains (losses)	**(86.4)**	148.3	(158)

In the year ended December 31, 2024, the Company recognized a total unrealized derivative loss of $86.4 million on its commodity contracts compared to a total unrealized derivative gain of $148.3 million in 2023. The unrealized crude oil derivative loss of $138.0 million in 2024 was primarily attributable to the change in forward benchmark crude oil prices relative to the Company's average hedge price. The unrealized derivative gain for natural gas of $51.6 million in 2024 was primarily due to the wider forward AECO to NYMEX differential at December 31, 2024 compared to December 31, 2023, partially offset by the maturity of in-the-money natural gas derivative contracts.

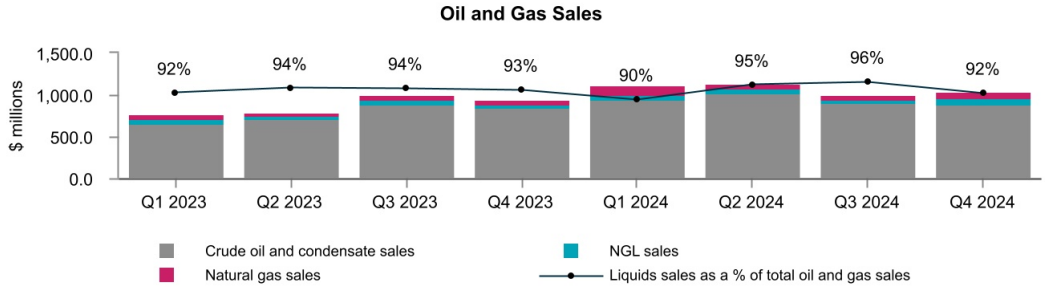
Oil and Gas Sales

($ millions) [1]	**2024**	2023	% Change
Crude oil and condensate sales	**3,741.9**	3,082.5	21
NGL sales	**235.6**	180.2	31
Natural gas sales	**293.8**	236.3	24
Total oil and gas sales	**4,271.3**	3,499.0	22

(1) Oil and gas sales are reported before realized commodity derivatives .

Total oil and gas sales increased by 22 percent in 2024 compared to 2023. The increase is due to higher production volumes, partially offset by lower average selling prices.

Exhibit 5



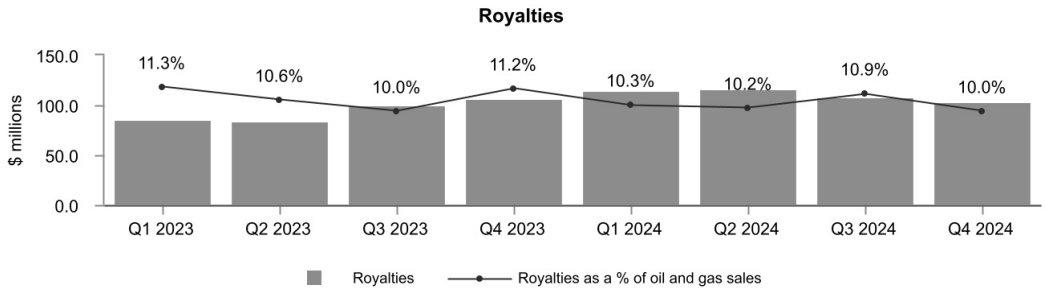
Royalties

($ millions, except % and per boe amounts)	**2024**	2023	% Change
Royalties	**441.7**	375.3	18
As a % of oil and gas sales	**10.3**	10.7	(0.4)
Per boe	**6.31**	7.43	(15)

Royalties increased 18 percent in 2024 compared to 2023 due to higher oil and gas sales, partially offset by a lower average royalty rate. Royalties as a percentage of oil and gas sales decreased slightly in 2024 compared to 2023, primarily due to the lower royalty rate associated with the Alberta Montney assets acquired in December 2023 and the non-core asset dispositions in the first half of 2024 that had higher royalty rates.

Royalties per boe decreased 15 percent in 2024 from the 2023 comparative year. This is primarily due to the addition of the Alberta Montney assets with a higher natural gas weighting and the lower royalty rate mentioned above.

Exhibit 6



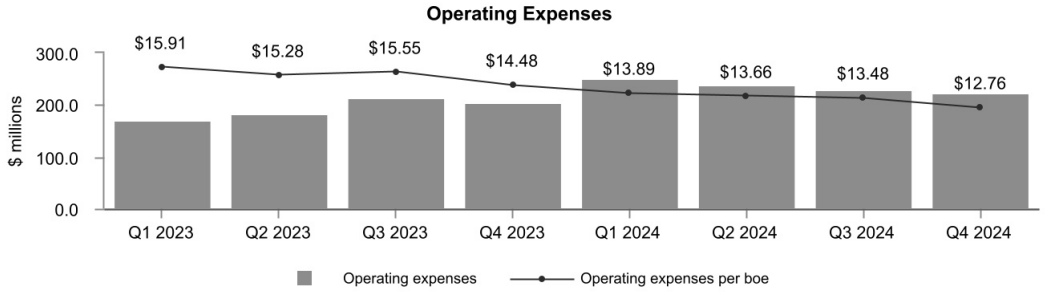
Operating Expenses

($ millions, except per boe amounts)	**2024**	2023	% Change
Operating expenses	**941.4**	770.5	22
Per boe	**13.46**	15.26	(12)

Operating expenses increased 22 percent in 2024 compared to 2023. The increase was primarily due to higher production as a result of the Alberta Montney acquisition in December 2023, partially offset by the dispositions of non-core assets in the first half of 2024.

Operating expenses per boe decreased by 12 percent in 2024 compared to 2023, primarily due to lower per boe operating costs associated with the acquired Alberta Montney assets and the dispositions mentioned above that had higher per boe operating costs.

Exhibit 7

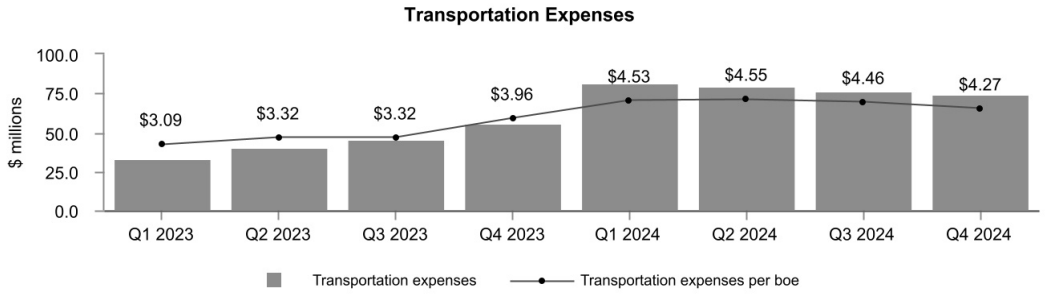


Transportation Expenses

($ millions, except per boe amounts)	**2024**	2023	% Change
Transportation expenses	**311.5**	174.3	79
Per boe	**4.45**	3.45	29

Transportation expenses increased 79 percent in 2024 compared to 2023, due to increased production and higher pipeline tolls. On a per boe basis, transportation expenses increased 29 percent in 2024 compared to 2023. The increase was primarily due to higher transportation fees associated with the Company's Alberta assets, which made up a larger proportion of production in 2024 compared to 2023. The higher transportation fees associated with these assets provides access to more favorable pricing in the Edmonton liquids market and U.S. Midwest natural gas market.

Exhibit 8



Netback

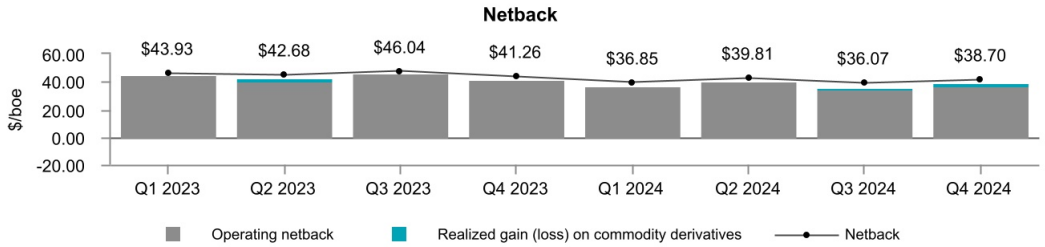
($/boe) [1]	**2024**	2023	% Change
Oil and gas sales	**61.05**	69.30	(12)
Royalties	**(6.31)**	(7.43)	(15)
Operating expenses	**(13.46)**	(15.26)	(12)
Transportation expenses	**(4.45)**	(3.45)	29
Operating netback [2]	**36.83**	43.16	(15)
Realized gain on commodity derivatives	**1.03**	0.31	232
Netback [2]	**37.86**	43.47	(13)

(1) The dominant production category for the Company's properties is crude oil and condensate. These categories include associated natural gas and NGL volumes. The combined operating netback and netback across all production categories have been presented.

(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

The Company's operating netback for the year ended December 31, 2024 decreased to $36.83 per boe from $43.16 per boe in 2023. The decrease in the Company's operating netback was primarily due to the decrease in average selling price and the increase in transportation expenses, partially offset by lower operating expenses and royalties. The decrease in the Company's netback was a result of the decrease in the operating netback, partially offset by an increased realized gain on commodity derivatives.

Exhibit 9



General and Administrative Expenses

($ millions, except per boe amounts)	**2024**	2023	% Change
Gross general and administrative expenses	**175.5**	179.0	(2)
Overhead recoveries	**(23.8)**	(18.2)	31
Capitalized	**(39.7)**	(34.3)	16
General and administrative expenses	**112.0**	126.5	(11)
Transaction costs	**(19.8)**	(39.8)	(50)
Net general and administrative expenses [1]	**92.2**	86.7	6
Per boe [1]	**1.32**	1.72	(23)

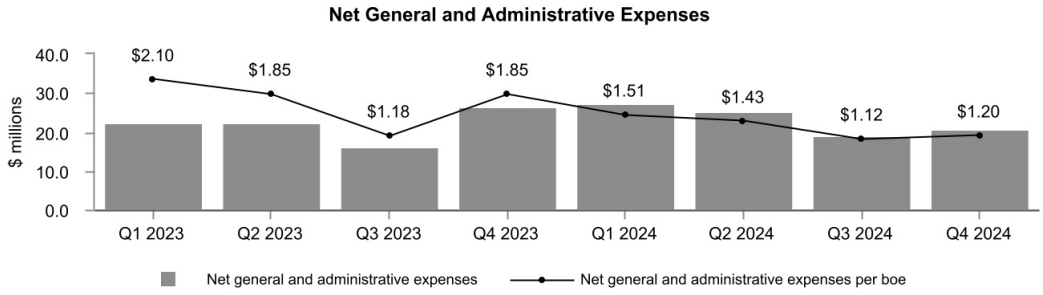
(1) Specified financial measures that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

Net general and administrative ("G&A") expenses increased to $92.2 million for the year ended December 31, 2024, compared to $86.7 million in 2023. The increase is primarily due to higher employee related and information systems costs.

For the year ended December 31, 2024, net G&A expenses on a per boe basis decreased 23 percent compared to 2023, primarily due to higher production volumes and synergies achieved through the Company's acquisitions.

Transaction costs relate to the Company's acquisition and disposition transactions. Refer to the *Capital Acquisitions and Dispositions* section in this MD&A for further information.

Exhibit 10



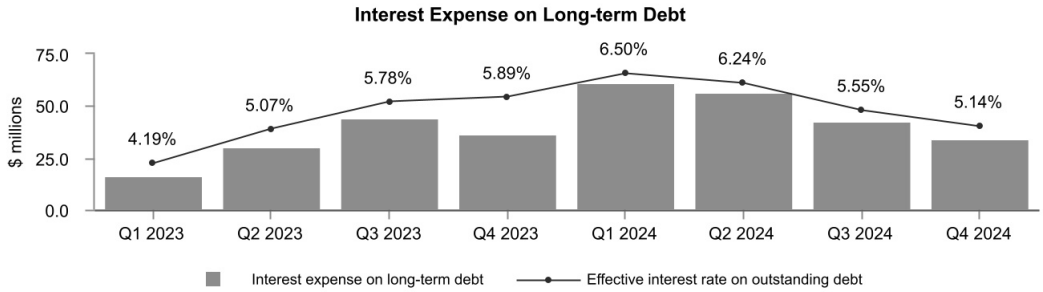
Interest Expense

($ millions, except per boe amounts)	**2024**	2023	% Change
Interest expense on long-term debt	**194.3**	126.0	54
Unrealized loss on interest derivative contracts	**—**	3.4	(100)
Interest expense	**194.3**	129.4	50
Per boe - continuing operations	**2.78**	2.56	9
Per boe - total average daily production	**2.78**	2.22	25

Interest expense on long-term debt increased 54 percent in the year ended December 31, 2024, compared to 2023, due to the Company's higher average debt balance and higher effective interest rate. For the year ended December 31, 2024, the Company's effective interest rate increased to 5.94 percent compared to 5.40 percent in 2023, due to the higher proportion of the Company's debt at floating rates in the first half of 2024.

At December 31, 2024, approximately 60 percent of the Company's outstanding long-term debt had fixed interest rates.

Exhibit 11



Foreign Exchange Gain

($ millions)	**2024**	2023	% Change
Translation of US dollar long-term debt	**(155.6)**	16.8	(1,026)
Realized gain on CCS - principal	**103.9**	151.8	(32)
Unrealized gain (loss) on CCS - principal	**43.5**	(155.8)	(128)
Foreign exchange gain (loss) related to US dollar long-term debt	**(8.2)**	12.8	(164)
Unrealized gain (loss) on foreign exchange swaps	**(3.2)**	2.2	(245)
Other	**17.4**	(5.0)	(448)
Foreign exchange gain	**6.0**	10.0	(40)

The Company records foreign exchange gains or losses on the period end translation of US dollar long-term debt and related accrued interest. The Company hedges its foreign exchange exposure on US dollar denominated long-term debt using cross currency swaps (“CCS”) to mitigate this foreign exchange exposure. During the year ended December 31, 2024, the Company recognized a foreign exchange loss related to US dollar long-term debt of $8.2 million, primarily related to the period end translation on US dollar private senior notes that do not have underlying CCS.

Share-based Compensation Expense

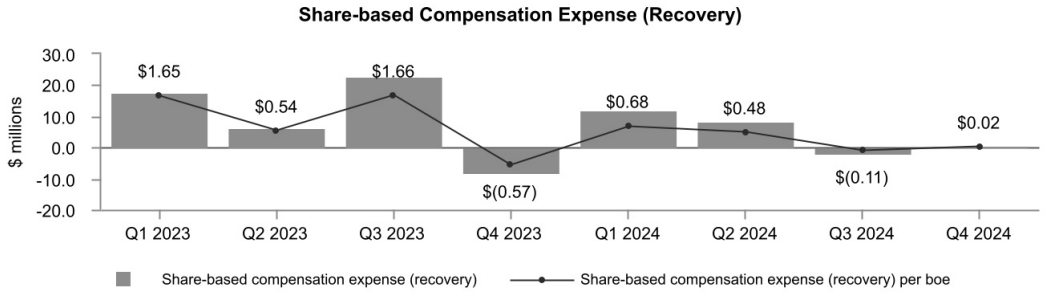
($ millions, except per boe amounts)	**2024**	2023	% Change
Share-based compensation costs	**19.7**	40.4	(51)
Realized gain on equity derivative contracts	**(4.5)**	(25.6)	(82)
Unrealized loss on equity derivative contracts	**9.3**	29.3	(68)
Capitalized	**(5.4)**	(5.4)	—
Share-based compensation expense	**19.1**	38.7	(51)
Per boe	**0.27**	0.77	(65)

During the year ended December 31, 2024, the Company recorded share-based compensation ("SBC") costs of $19.7 million compared to $40.4 million in 2023. The decrease in SBC costs is primarily attributable to the lower share price at December 31, 2024 as compared to December 31, 2023 and lower performance achievements associated with the Performance Share Unit ("PSU") plan in 2024 relative to 2023.

In 2024, the Company recognized a realized gain of $4.5 million on in-the-money equity derivative contracts that matured in the first quarter of 2024. The realized gain is primarily due to the increase in the Company's share price on the maturity date compared to the hedge price at the time of grant.

During the year ended December 31, 2024, the Company recognized an unrealized loss on equity derivative contracts of $9.3 million compared to $29.3 million in 2023. The unrealized loss in 2024 was primarily due to the decrease in the Company's share price at December 31, 2024 compared to the grant date, as well as maturity of in-the-money equity derivative contracts in the first quarter of 2024.

Exhibit 12



The following table summarizes the number of restricted shares, Employee Share Value Plan ("ESVP") awards, PSUs, Deferred Share Units ("DSUs") and stock options outstanding:

	December 31, 2024	December 31, 2023
Restricted Share Bonus Plan [1]	**1,119,165**	1,380,685
Employee Share Value Plan	**2,848,960**	2,660,066
Performance Share Unit Plan [2]	**2,106,192**	1,623,248
Deferred Share Unit Plan	**1,951,870**	1,728,423
Stock Option Plan [3]	**713,876**	3,224,260

(1) At December 31, 2024, the Company was authorized to issue up to 9,041,281 common shares (December 31, 2023 - 9,774,533 common shares).

(2) Based on underlying units before any effect of performance multipliers.

(3) At December 31, 2024, the weighted average exercise price is $5.93 per share (December 31, 2023 - $4.74 per share).

As of the date of this MD&A, the Company had 1,119,165 restricted shares, 2,790,781 ESVP awards, 3,690,288 PSUs, 2,000,073 DSUs and 445,407 stock options outstanding.

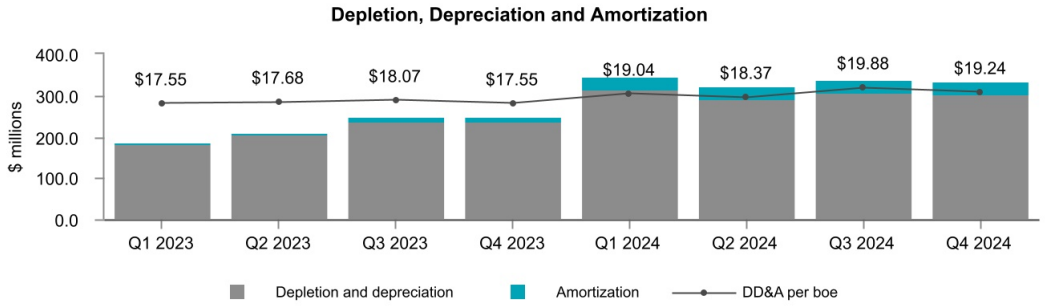
Depletion, Depreciation and Amortization

($ millions, except per boe amounts)	**2024**	2023	% Change
Depletion and depreciation	**1,215.7**	863.8	41
Amortization of exploration and evaluation undeveloped land	**122.6**	30.9	297
Depletion, depreciation and amortization	**1,338.3**	894.7	50
Per boe	**19.13**	17.72	8

The Company's depletion, depreciation and amortization ("DD&A") rate increased to $19.13 per boe in 2024 compared to $17.72 per boe in 2023. The increase in the DD&A rate per boe in 2024 was due to the increase in amortization of exploration and evaluation ("E&E") undeveloped land, primarily as a result of the acquisition of the Alberta Montney assets in May 2023 and December 2023.

For the year ended December 31, 2024, DD&A expense increased 50 percent compared to 2023, due to higher production volumes and DD&A rates in 2024.

Exhibit 13



Impairment

($ millions, except per boe amounts)	**2024**	2023	% Change
Impairment	**512.3**	93.8	446
Per boe	**7.32**	1.86	294

Veren recognized an impairment loss of $512.3 million in the first quarter of 2024 and $93.8 million in 2023, related entirely to non-core assets classified as held for sale, which were subsequently disposed. At March 31, 2024, the Company classified certain non-core assets in its Southeast Saskatchewan and Southwest Saskatchewan CGUs as held for sale. Immediately prior to classifying the assets as held for sale and at the balance sheet date, the Company conducted a review of the assets' estimated recoverable amounts and recorded impairment losses of $486.8 million on Property, Plant & Equipment ("PP&E") and $25.5 million on goodwill. The recoverable amount was determined based on the assets' fair value less costs of disposal and based on expected consideration.

Taxes

($ millions)	**2024**	2023	% Change
Current tax recovery	**—**	(0.7)	(100)
Deferred tax expense	**59.8**	254.4	(76)

Current Tax Recovery

In the year ended December 31, 2024, the Company recorded current tax expense of nil, compared to a current tax recovery of $0.7 million for the year ended December 31, 2023. Refer to the Company's Annual Information Form ("AIF") for the year ended December 31, 2024 for information on the Company's expected tax horizon, which is available on SEDAR+ at www.sedarplus.ca. Additionally, our AIF forms part of our Form 40-F that is filed with the SEC and is available on EDGAR at www.sec.gov.

Deferred Tax Expense

In the year ended December 31, 2024, the Company recorded deferred tax expense of $59.8 million compared to $254.4 million in 2023. The decrease in the deferred tax expense in 2024 primarily relates to a decrease in net income before taxes.

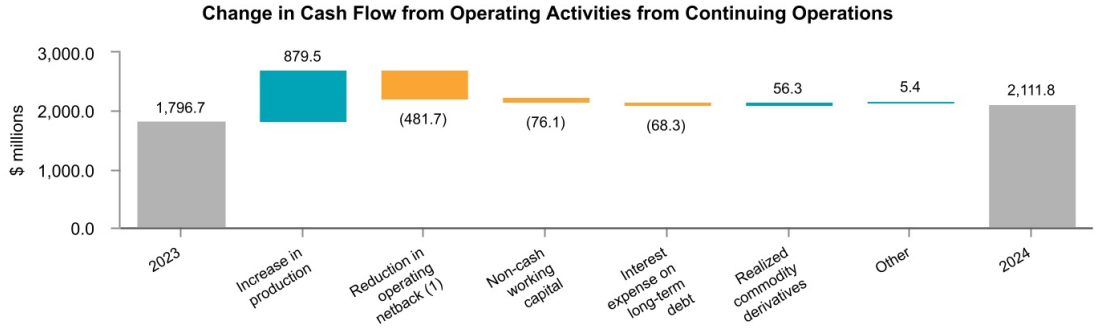
Cash Flow from Operating Activities, Adjusted Funds Flow from Operations, Net Income and Adjusted Net Earnings from Operations

($ millions, except per share amounts)	**2024**	2023	% Change
Cash flow from operating activities from continuing operations	**2,111.8**	1,796.7	18
Adjusted funds flow from continuing operations [(1)]	**2,347.8**	1,975.6	19
Net income from continuing operations	**283.9**	799.4	(64)
Net income from continuing operations per share - diluted	**0.46**	1.46	(68)
Adjusted net earnings from continuing operations [(1)]	**848.8**	795.9	7
Adjusted net earnings from continuing operations per share - diluted [(1)]	**1.37**	1.45	(6)

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

In the year ended December 31, 2024, cash flow from operating activities from continuing operations increased to $2.11 billion from $1.80 billion in 2023. The increase was primarily due to increased production and realized gains on commodity derivatives, partially offset by the lower operating netback, changes in non-cash working capital and higher interest expense on long-term debt.

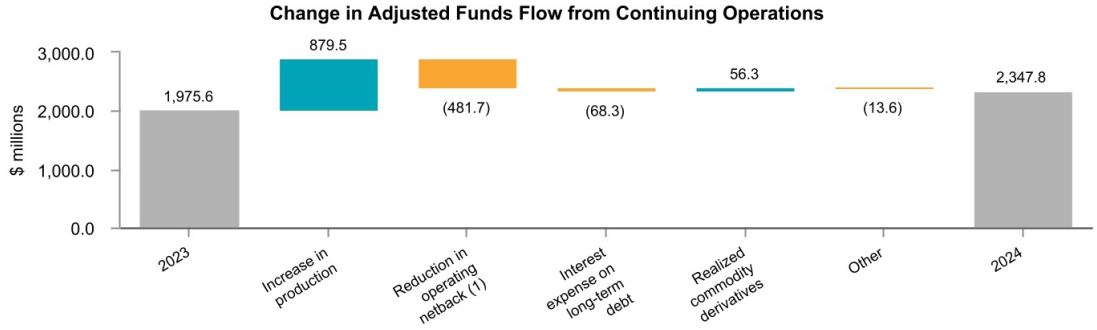
Exhibit 14



(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

Adjusted funds flow from continuing operations increased in 2024 to $2.35 billion compared to $1.98 billion in 2023. The increase in adjusted funds flow from continuing operations was primarily due to increased production and realized gains on commodity derivatives, partially offset by the lower operating netback and higher interest expense on long-term debt.

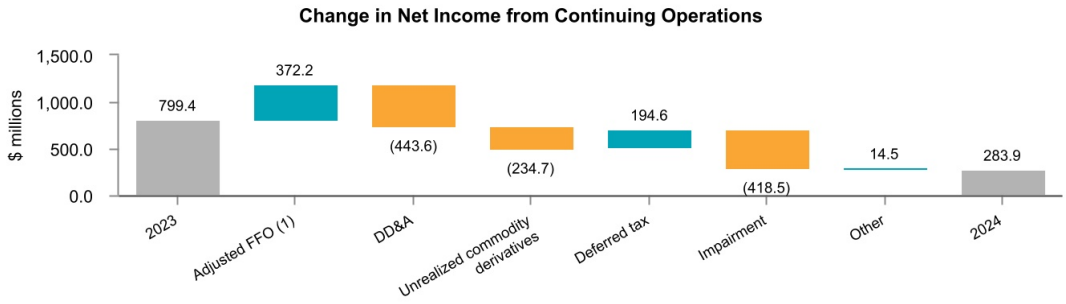
Exhibit 15



(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

In the year ended December 31, 2024, the Company reported net income from continuing operations of $283.9 million ($0.46 per fully diluted share) compared to $799.4 million in 2023 ($1.46 per fully diluted share). The decrease in net income in 2024 was primarily due to higher DD&A, higher impairment expense related to assets held for sale and unrealized commodity derivative losses, partially offset by higher adjusted funds flow from continuing operations and lower deferred tax expense.

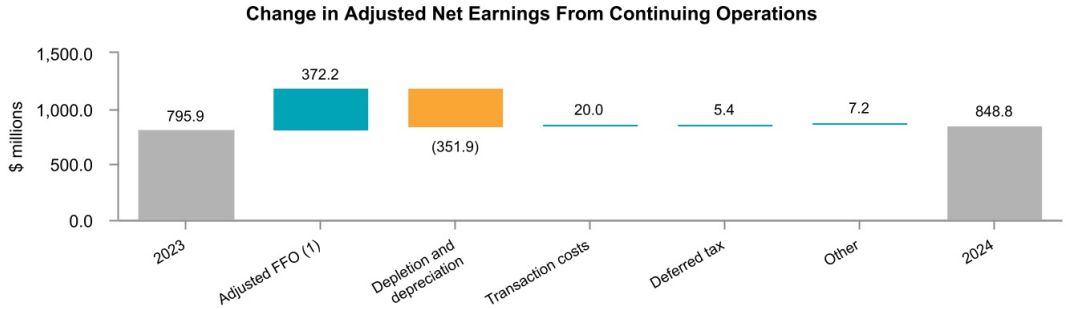
Exhibit 16



(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

Adjusted net earnings from continuing operations in the year ended December 31, 2024 was $848.8 million ($1.37 per fully diluted share) compared to $795.9 million in 2023 ($1.45 per fully diluted share). The increase in adjusted net earnings from continuing operations was primarily due to higher adjusted funds flow from continuing operations, partially offset by higher depletion and depreciation expense.

Exhibit 17



(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

Excess Cash Flow

For the year ended December 31, 2024, corporate excess cash flow decreased to $641.6 million from $981.6 million in 2023. The decrease was primarily due to higher development capital and other expenditures.

Discontinued Operations

($ millions, except per share amounts)	**2024**	2023	% Change
Cash flow from operating activities from discontinued operations	**—**	399.0	(100)
Adjusted funds flow from discontinued operations [1]	**—**	363.5	(100)
Net income (loss) from discontinued operations	**(10.6)**	(229.1)	(95)
Net income (loss) from discontinued operations per share - diluted	**(0.02)**	(0.42)	(95)
Adjusted net earnings from discontinued operations [1]	**—**	136.7	(100)
Adjusted net earnings from discontinued operations per share - diluted [1]	**—**	0.25	(100)

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

In 2023, the Company disposed of its entire Northern U.S. CGU, which was comprised of producing assets in North Dakota and represented a distinct geographical area of the Company's operations. In accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*, the results from this CGU were classified as discontinued operations.

For the year ended December 31, 2024, the Company recognized a net loss from discontinued operations of $10.6 million compared to $229.1 million in 2023. The net loss in 2024 was a result of final closing adjustments related to the sale of the North Dakota assets.

Dividends Declared

($ millions, except per share amounts)	**2024**	2023	% Change
Dividends declared	**284.6**	211.9	34
Dividends declared per share	**0.460**	0.387	19

In October 2024, the Company declared a quarterly dividend of $0.115 per share that was paid on January 2, 2025.

In 2024, the Company declared total cash dividends of $0.460 per share compared to $0.387 per share in 2023.

Related Party Transactions

Key management personnel of the Company consists of its directors and executive officers. For the year ended December 31, 2024, the compensation recorded as short-term benefits relating to key management personnel was $6.7 million (year ended December 31, 2023 - $7.3 million). Short-term benefits include salaries and directors' fees, annual bonuses and other benefits. In addition, the Company provides share-based compensation under its RSU, PSU, DSU and stock option plans. For the year ended December 31, 2024, share-based compensation costs relating to key management personnel was $3.2 million (year ended December 31, 2023 - $19.4 million).

Capital Expenditures

($ millions)	**2024**	2023	% Change
Development capital expenditures [1]	**1,508.1**	1,138.7	32
Land expenditures	**41.8**	33.6	24
Capitalized administration [2]	**45.1**	42.3	7
Corporate assets	**5.7**	5.9	(3)
Capital acquisitions [1]	**32.4**	4,589.7	(99)
Capital dispositions [1] [3]	**(1,037.7)**	(613.6)	69
Total [4]	**595.4**	5,196.6	(89)

(1) Specified financial measures that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

(2) Capitalized administration excludes capitalized equity-settled SBC.

(3) Includes dispositions recorded through assets held for sale.

(4) Includes both continuing and discontinued operations.

Capital Acquisitions and Dispositions

Major Property Dispositions

North Dakota disposition

In 2023, the Company completed the disposition of its North Dakota assets for total consideration of $585.8 million, consisting of $504.6 million in cash and $81.2 million in deferred consideration receivable. In the year ended December 31, 2024, the Company incurred $12.7 million in final closing adjustments related to the disposition. Refer to the *Discontinued Operations* section in this MD&A for further information.

Southern Alberta disposition

On January 26, 2024, the Company completed the disposition of its Southern Alberta assets for total cash consideration of $37.1 million, including closing adjustments. Total consideration consisted of $12.1 million in cash and $25.0 million of deferred consideration receivable. These assets were recorded as assets held for sale at December 31, 2023.

Swan Hills disposition

On March 21, 2024, the Company completed the disposition of its Swan Hills assets in Northern Alberta for total cash consideration of $80.5 million, including closing adjustments. These assets were recorded as assets held for sale at December 31, 2023.

Non-core Saskatchewan disposition

On June 14, 2024, the Company completed the disposition of certain non-core assets in its Southeast Saskatchewan and Southwest Saskatchewan CGUs for total cash consideration of $531.6 million, including closing adjustments. These assets were recorded as assets held for sale at March 31, 2024.

Montney Infrastructure transaction

On October 9, 2024, Veren closed its strategic Alberta Montney infrastructure transaction, disposing of four Company owned batteries for cash consideration of $400.0 million. These assets were recorded as assets held for sale at September 30, 2024. Concurrent with the transaction, the Company re-negotiated certain processing and handling agreements in the Alberta Montney area to improve operational efficiencies. As part of these agreements, the Company gained operatorship of four third-party batteries and maintained operatorship of the batteries disposed. The agreements include a long-term fixed take-or-pay commitment, which has been recorded as a lease and a sale and leaseback in accordance with IFRS 16 *Leases*. See Note 14 - "Leases" in the audited consolidated financial statements for the year ended December 31, 2024 for additional information.

Development Capital Expenditures

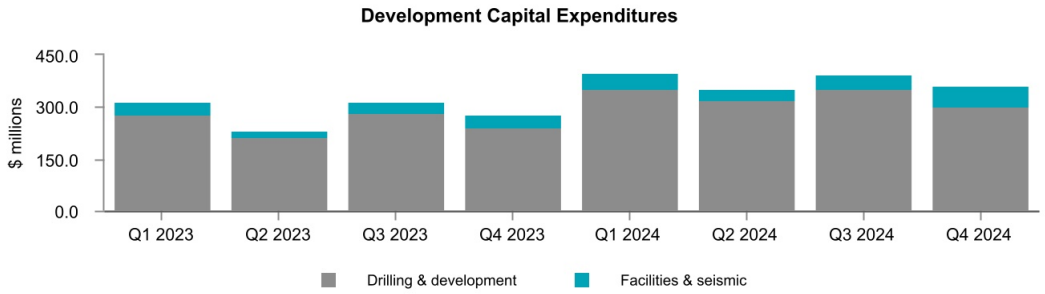
($ millions)	**2024**	2023	% Change
Development capital expenditures from continuing operations [(1)]	**1,508.1**	844.9	78
Development capital expenditures from discontinued operations [(1)]	**—**	293.8	(100)
Development capital expenditures [(1)]	**1,508.1**	1,138.7	32

(1) Specified financial measures that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

The Company's development capital expenditure for the year ended December 31, 2024 were $1.51 billion compared to $1.14 billion in 2023. The increased spending in 2024 was primarily focused on development in the Alberta Montney and Kaybob Duvernay areas. In the year ended December 31, 2024, 180 (165.8 net) wells were drilled and $184.3 million was spent on facilities and seismic (2023 - $121.8 million).

Refer to the *Guidance* section in this MD&A for Veren's development capital expenditure guidance for 2025.

Exhibit 18



Goodwill

The Company's goodwill balance is attributable to corporate acquisitions completed during the period from 2003 through 2023. The goodwill balance as at December 31, 2024 was $243.8 million compared to $275.9 million at December 31, 2023. The decrease of $32.1 million is primarily attributable to the impairment recorded on goodwill related to assets held for sale and the disposition of the Southern Alberta and Swan Hills assets in 2024.

Other Current Liabilities

At December 31, 2024, other current liabilities consist of $15.5 million related to the current portion of long-term share-based compensation, $59.5 million related to the current portion of lease liabilities, and $20.0 million related to decommissioning liability.

Other Long-Term Liabilities

At December 31, 2024, other long-term liabilities consist of $24.2 million of long-term compensation liability related to share-based compensation.

Lease Liability

At December 31, 2024, the Company had $611.1 million of lease liabilities for contracts related to facilities, office space, fleet vehicles, equipment and drilling rigs.

Decommissioning Liability

The decommissioning liability, including liabilities associated with assets held for sale, decreased by $158.8 million during 2024, from $738.8 million at December 31, 2023 to $580.0 million at December 31, 2024. The decrease primarily relates to liabilities disposed through assets held for sale and the Company's continued abandonment and reclamation program, partially offset by changes in estimated future costs. The liability is based on estimated undiscounted cash flows before inflation to settle the obligation of $827.9 million.

Liquidity and Capital Resources

Capitalization Table ($ millions, except share, per share, ratio and percent amounts)	**December 31, 2024**	December 31, 2023
Net debt [1]	**2,477.9**	3,738.1
Shares outstanding	**611,816,627**	619,929,490
Market price at end of period (per share)	**7.39**	9.19
Market capitalization	**4,521.3**	5,697.2
Enterprise value [1]	**6,999.2**	9,435.3
Net debt as a percentage of enterprise value [1]	**35**	40
Adjusted funds flow from operations [1] [2]	**2,347.8**	2,339.1
Net debt to adjusted funds flow from operations [1] [3]	**1.1**	1.6

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

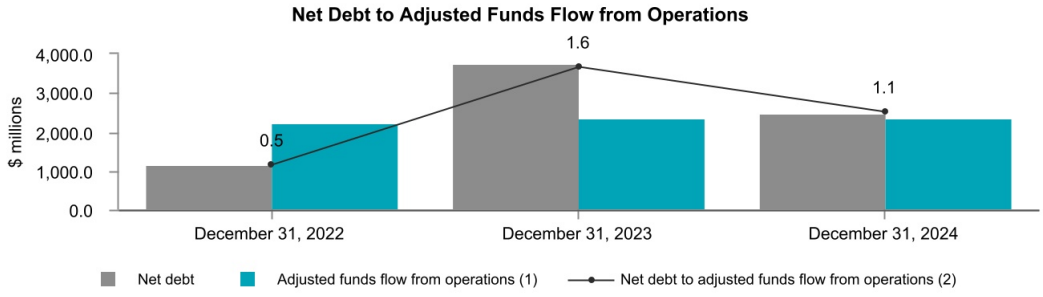
(2) The sum of adjusted funds flow from operations for the trailing four quarters. Includes both continuing and discontinued operations.

(3) The net debt reflects the financing of acquisitions, however, the adjusted funds flow from operations only reflects adjusted funds flow from operations generated from the acquired properties since the closing date of the acquisitions.

At December 31, 2024, Veren's enterprise value was $7.00 billion and the Company was capitalized with 65 percent equity compared to $9.44 billion and 60 percent at December 31, 2023, respectively. The decrease in enterprise value at December 31, 2024 compared to December 31, 2023 is due to the reduction in net debt and the Company's lower market capitalization. The Company's net debt to adjusted funds flow from operations ratio at December 31, 2024, decreased to 1.1 times from 1.6 times at December 31, 2023. The decrease was largely due to the reduction in net debt as a result of capital dispositions and excess cash flow generation in the year ended December 31, 2024.

Veren's market capitalization decreased to $4.52 billion at December 31, 2024 from $5.70 billion at December 31, 2023, primarily due to the decrease in the Company's share price and the lower number of shares outstanding due to the impact of the shares purchased for cancellation under the Company's Normal Course Issuer Bid ("NCIB").

Exhibit 19



(1) The sum of adjusted funds flow from operations for the trailing four quarters.

(2) The net debt reflects the financing of acquisitions, however, the adjusted funds flow from operations only reflects adjusted funds flow from operations generated from the acquired properties since the closing date of the acquisitions.

At December 31, 2024, the Company had combined facilities of $2.36 billion. This includes a $2.26 billion syndicated unsecured credit facility and a $100.0 million unsecured operating credit facility, both with a current maturity date of November 26, 2028. Both of these facilities constitute revolving credit facilities and are extendible annually.

At December 31, 2024, the Company had available unused borrowing capacity on its revolving bank credit facilities of approximately $1.45 billion, including cash of $17.1 million.

The Company has a $60.0 million unsecured demand letter of credit facility. The Company had letters of credit in the amount of $43.0 million outstanding at December 31, 2024.

During the second quarter of 2024, the Company issued Cdn$1.00 billion of investment grade public senior notes, consisting of Cdn$550.0 million of 4.968% notes priced at par and due June 2029, and Cdn$450.0 million of 5.503% notes priced at par and due June 2034. The net proceeds from the offering were used to repay existing indebtedness under bank facilities, including fully retiring the Company's bank term loan.

At December 31, 2024, the Company had outstanding private senior notes of US$332.0 million and Cdn$65.0 million and public senior notes of Cdn$1.00 billion. The private senior notes have financial covenants similar to those of the combined credit facilities described above. There are no financial covenants associated with the public senior notes.

Concurrent with the issuance of private senior notes with total principal of US$259.5 million, the Company entered into CCS to manage the Company's foreign exchange risk. CCS fixes the US dollar amount of the individual tranches of notes for purposes of interest and principal repayments at a notional amount of $330.5 million. At December 31, 2024, $471.1 million of notional principal was repayable within one year. See Note 27 - "Financial Instruments and Derivatives" in the audited consolidated financial statements for the year ended December 31, 2024 for additional information.

The Company is in compliance with all debt covenants at December 31, 2024, which are listed in the table below:

Covenant Description	Maximum Ratio	**December 31, 2024**
Senior debt to adjusted EBITDA [(1) (2)]	3.50	**0.97**
Total debt to adjusted EBITDA [(1) (3)]	4.00	**0.97**
Total debt to capital [(2) (3) (4)]	0.60	**0.27**

(1) Adjusted EBITDA is calculated as earnings before interest, taxes, depletion, depreciation, amortization, impairment and impairment reversals, adjusted for certain non-cash items. Adjusted EBITDA is calculated on a trailing 12 month basis adjusted for material acquisitions and dispositions.

(2) Senior debt is calculated as the sum of amounts drawn on the combined facilities, outstanding letters of credit and the principal amount of the senior notes.

(3) Total debt is calculated as the sum of senior debt plus subordinated debt. Veren does not have any subordinated debt.

(4) Capital is calculated as the sum of senior debt and shareholders' equity and excludes the effect of unrealized derivative gains or losses and the adoption of IFRS 16.

The Company's ongoing working capital requirements are expected to be financed through cash, adjusted funds flow from operations and its bank credit facilities.

Shareholders' Equity

At December 31, 2024, Veren had 611.8 million common shares issued and outstanding compared to 619.9 million common shares at December 31, 2023. The decrease of 8.1 million is primarily due to shares purchased for cancellation under the Company's current NCIB, partially offset by stock options exercised pursuant to the Stock Option Plan and shares issued pursuant to the Restricted Share Bonus Plan.

As of the date of this MD&A, the Company had 611,816,627 common shares outstanding.

Normal Course Issuer Bid

On March 7, 2024, the Company announced the approval by the Toronto Stock Exchange of its notice to implement an NCIB. The NCIB commenced on March 11, 2024 and is due to expire on March 10, 2025. The NCIB allows the Company to purchase, for cancellation, up to 61,663,522 common shares, or 10 percent of the Company's public float, as at February 29, 2024. The Company intends to renew the NCIB. The Company's previous NCIB commenced on March 9, 2023 and expired on March 8, 2024.

During the year ended December 31, 2024, the Company purchased 10.4 million common shares for total consideration of $101.1 million under its current NCIB. Total costs paid, including commissions, fees and taxes are recognized directly as a reduction in shareholders' equity. Under the NCIB, all common shares purchased are cancelled.

Contractual Obligations and Commitments

At December 31, 2024, the Company had contractual obligations and commitments as follows:

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Off balance sheet commitments					
Operating [1]	16.1	20.9	10.4	2.6	50.0
Gas processing	87.5	174.0	143.4	469.3	874.2
Transportation	253.2	391.6	373.1	507.8	1,525.7
Total contractual commitments [2]	356.8	586.5	526.9	979.7	2,449.9

(1) Includes operating costs on the Company's office space, net of $17.2 million recoveries from subleases.

(2) Excludes contracts accounted for under IFRS 16. See Note 14 - "Leases" in the annual consolidated financial statements for the year ended December 31, 2024 for further information.

($ millions)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Other contractual commitments					
Senior notes [1]	534.0	134.8	640.5	561.4	1,870.7
Bank debt [2]	59.7	113.2	971.5	—	1,144.4
Total contractual commitments	593.7	248.0	1,612.0	561.4	3,015.1

(1) These amounts include the notional principal and interest payments pursuant to the related CCS which fix the amounts due in Canadian dollars. US dollar private senior notes that do not have any underlying CCS are translated at the period end foreign exchange rate.

(2) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2024, and includes undiscounted cash outflows pursuant to the CCS related to Secured Overnight Financing Rate loans.

Off Balance Sheet Arrangements

The Company has off-balance sheet arrangements consisting of various contracts which are entered into in the normal course of operations. Contracts that contain a lease are accounted for under IFRS 16 and recorded on the balance sheet as at December 31, 2024. All other contracts which are entered into in the normal course of operations are captured in the "off balance sheet commitments" table in the *Contractual Obligations and Commitments* section above and no asset or liability value has been assigned to these contracts on the balance sheet as at December 31, 2024.

Critical Accounting Estimates

The preparation of the Company's consolidated financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. A summary of the significant accounting policies used by Veren can be found in Note 3 - "Material Accounting Policies" in the audited consolidated financial statements for the year ended December 31, 2024. The following discussion outlines what management believes are the most critical policies involving the use of estimates and assumptions.

Oil and gas activities

Reserves estimates, although not reported as part of the Company's consolidated financial statements, can have a significant effect on net income, assets and liabilities as a result of their impact on DD&A, decommissioning liability, deferred taxes, asset impairments and impairment reversals, and business combinations. Independent petroleum reservoir engineers perform evaluations of the Company's oil and gas reserves on an annual or as needed basis. The estimation of oil and gas reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

For purposes of impairment testing, PP&E is aggregated into CGUs, based on separately identifiable and largely independent cash inflows. The determination of the Company's CGUs is subject to judgment. Factors considered in the classification of CGUs 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 regarding operations.

The determination of technical feasibility and commercial viability is subject to judgment as it is based on the presence of reserves and results in the transfer of assets from E&E to PP&E.

Decommissioning liability

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are based on estimates with respect to the cost and timing of decommissioning.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of oil and gas reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected as a result of changes in future DD&A, asset impairment or goodwill impairment.

Fair value measurement

The estimated fair value of derivative instruments resulting in derivative assets and liabilities, by its very nature, is subject to measurement uncertainty. Estimates included in the determination of the fair value of derivative instruments include forward benchmark prices, discount rates, share price and forward foreign exchange rates.

Joint control

Judgment is required to determine when the Company has joint control over an arrangement, which requires an assessment of the capital and operating activities of the projects it undertakes with partners and when the decisions in relation to those activities require unanimous consent.

Share-based compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax assets and liabilities recognize the extent that temporary differences will be receivable and payable in future periods. The calculation of the related asset and liability 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, expected cash flows from estimated proved plus probable oil and gas reserves and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

Risk Factors

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have an impact on Veren’s business. Financial risks the Company is exposed to include: marketing production at an acceptable price given market conditions and market access; finding and producing oil and gas reserves at a reasonable cost; volatility in market prices for oil and natural gas; volatility in crude oil price differentials; fluctuations in foreign exchange and interest rates; tariffs; stock market volatility; debt service which may limit timing or amount of dividends as well as market price of shares; the continued availability of adequate debt and equity financing and cash flow to fund planned expenditures; sufficient liquidity for future operations; lost revenue or increased expenditures as a result of delayed or denied environmental, safety or regulatory approvals; adverse changes to income tax laws or other laws or government incentive programs and regulations relating to the oil and gas industry; cost of capital risk to carry out the Company’s operations; and uncertainties associated with credit facilities and counterparty credit risk.

Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on the Company’s ability to achieve objectives. Operational risks to which Veren is exposed include: uncertainties associated with estimating oil and natural gas reserves; incorrect assessments of the value of acquisitions and exploration and development programs; failure to realize the anticipated benefits of acquisitions and dispositions; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; inability to secure adequate product transportation including sufficient crude-by-rail or other alternate transportation; delays in business operations, pipeline restrictions, public infrastructure constraints including blockades and blowouts; unforeseen title defects; increased competition for, among other things, capital, acquisitions of oil and gas reserves and undeveloped lands; competition for and availability of qualified personnel or management; outbreaks; mobility restrictions, loss and health of key personnel; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; competitive action by other companies; the ability of suppliers to meet commitments and risks; and cyber security risks.

Potential drought conditions can result in a higher likelihood of water restrictions and increased susceptibility to wildfire conditions. During drought conditions provincial regulators can restrict water license allocations and limit the water we use that are critical to our operations. Wildfires may restrict the Company's ability to access and operate its properties and cause operational difficulties, including damage to equipment and infrastructure. Wildfires also increase the risk of personnel injury as a result of dangerous working conditions.

Safety, Environmental and Regulatory Risks

Safety, environmental and regulatory risks are the risks of loss or lost opportunity resulting from changes to laws governing safety, the environment, royalties and taxation. Safety, environmental and regulatory risks Veren is exposed to include: the risk of wildfires or drought; indigenous land claims; uncertainties associated with regulatory approvals; uncertainty of government policy changes; the risk of carrying out operations with minimal environmental impact; changes in or adoption of new laws and regulations or changes in how they are interpreted or enforced; obtaining required approvals of regulatory authorities and stakeholder support for activities and growth plans.

The Company’s operations are subject to costs being incurred to pay carbon taxes, to reduce Greenhouse Gas ("GHG") emissions (including methane emissions) and to perform necessary monitoring, measurement, verification and reporting of GHG emissions. Future environmental legislation may require further reductions in emissions from the Company’s operations and result in increased capital and operational expenditures related to the transition to a low-carbon economy.

Refer to the Company's Annual Information Form for the year ended December 31, 2024 for additional information on the Company's risk factors.

Risk Management

Veren is committed to identifying and managing its risks in the near term, as well as on a strategic and longer term basis at all levels in the organization in accordance with the Company's Board-approved Risk Management and Counterparty Credit Policy and risk management programs. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. Veren takes a proactive approach to the identification and management of issues that can affect the Company’s assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management.

Specific actions Veren takes to ensure effective risk management include but are not limited to: employing qualified professional and technical staff; concentrating in a limited number of areas with lower risk development projects; utilizing market proven technology for finding and developing oil and gas reserves; constructing quality, environmentally sensitive and safe production facilities; adopting and communicating sound policies governing all areas of our business; maximizing operational control of drilling and production operations; strategic hedging program including commodity prices, interest and foreign exchange rates; adhering to conservative borrowing guidelines and maintaining significant liquidity; monitoring counterparty creditworthiness and obtaining supplementary credit protection when warranted.

Changes in Accounting Policies

Presentation of Financial Statements

IAS 1 *Presentation of Financial Statements* was amended in January 2020 by the International Accounting Standards Board to clarify the presentation requirements of liabilities as either current or non-current within the statement of financial position. The Company adopted this amendment in 2024 and the adoption did not have an impact on the Company's annual consolidated financial statements.

Income Taxes

IAS 12 *Income Taxes* was amended in May 2023 by the International Accounting Standards Board to provide guidance on deferred taxes arising in jurisdictions implementing the *Pillar Two model rules* published by the Organisation for Economic Co-operation and Development. This amendment was effective immediately and has been adopted by the Company with no impact to the Company's annual consolidated financial statements.

Lease Liability in a Sale and Leaseback

In September 2022, the International Accounting Standards Board issued narrow-scope amendments to IFRS 16*Leases,* which applies to sale and leaseback transactions that include variable lease payments. The amendments specify that no gain or loss can be recognized on the rights retained by the seller-lessee, and require the inclusion of variable payments that do not depend on an index or rate in the initial measurement of the right-of-use asset and lease liability. These amendments were effective for fiscal years beginning on or after January 1, 2024. In the current accounting period, the Company adopted the narrow-scope amendments. See Note 14 - "Leases" in the annual consolidated financial statements for the year ended December 31, 2024 for additional information regarding transactions impacted by these amendments.

New accounting standards and amendments not yet adopted

Presentation and Disclosure in Financial Statements

IFRS 18 *Presentation and Disclosure in Financial Statements* was issued in April 2024 by the International Accounting Standards Board and replaces IAS 1 *Presentation of Financial Statements*. The Standard introduces a defined structure to the statements of comprehensive income and specific disclosure requirements related to the same. The Standard is required to be adopted retrospectively and is effective for fiscal years beginning on or after January 1, 2027, with early adoption permitted. The Company is evaluating the impact that this standard will have on the consolidated financial statements.

Financial Instruments* and *Financial Instruments: Disclosures

IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* were amended in May 2024 to clarify the date of recognition and derecognition of financial assets and liabilities. The amendments are effective for fiscal years beginning on or after January 1, 2026, with early adoption permitted. The Company is evaluating the impact that this amendment will have on the consolidated financial statements.

Selected Annual Information

($ millions, except per share amounts)	**2024**	2023	2022
Oil and gas sales from continuing operations	**4,271.3**	3,499.0	3,847.0
Total oil and gas sales	**4,271.3**	4,111.9	4,493.1
Average daily production from continuing operations			
Crude oil and condensate (bbls/d)	**107,541**	88,087	79,323
NGLs (bbls/d)	**17,533**	15,026	13,079
Natural gas (mcf/d)	**396,534**	211,275	128,099
Production from continuing operations (boe/d)	**191,163**	138,326	113,752
Total average daily production (boe/d)	**191,163**	159,411	132,282
Net income from continuing operations	**283.9**	799.4	1,146.7
Net income per share from continuing operations - diluted	**0.46**	1.46	2.01
Net income	**273.3**	570.3	1,483.4
Net income per share - diluted	**0.44**	1.04	2.60
Adjusted net earnings from continuing operations (1)	**848.8**	795.9	764.1
Adjusted net earnings from continuing operations per share – diluted (1)	**1.37**	1.45	1.34
Adjusted net earnings from operations (1)	**848.8**	932.6	965.7
Adjusted net earnings from operations per share – diluted (1)	**1.37**	1.70	1.69
Cash flow from operating activities from continuing operations	**2,111.8**	1,796.7	1,828.7
Cash flow from operating activities	**2,111.8**	2,195.7	2,192.2
Adjusted funds flow from continuing operations (1)	**2,347.8**	1,975.6	1,848.6
Adjusted funds flow from operations (1)	**2,347.8**	2,339.1	2,232.4
Adjusted working capital surplus (deficiency) (1)	**(90.9)**	(196.3)	95.1
Total assets	**11,751.0**	12,775.7	9,486.4
Total liabilities	**4,990.0**	5,908.2	2,993.0
Net debt (1)	**2,477.9**	3,738.1	1,154.7
Weighted average shares - diluted (millions)	**618.9**	548.3	571.1
Total capital acquisitions (1)	**32.4**	4,589.7	90.7
Total capital dispositions (1)	**(1,037.7)**	(613.6)	(283.6)
Development capital expenditures from continuing operations (1)	**1,508.1**	844.9	698.0
Development capital expenditures (1)	**1,508.1**	1,138.7	956.1
Dividends declared	**284.6**	211.9	200.6
Dividends declared per share	**0.460**	0.387	0.360

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

Veren's oil and gas sales, cash flow from operating activities, adjusted funds flow from operations and total assets have fluctuated for the years 2022 through 2024, primarily due to changes in the Cdn$ WTI benchmark prices and corporate oil price differentials, numerous acquisitions and dispositions and the Company's drilling program.

Net income over the past three years has fluctuated, primarily due to unrealized derivative gains and losses on commodity contracts, which fluctuate with changes in market conditions, and PP&E impairment charges and reversals, along with associated fluctuations in deferred tax expense (recovery).

Adjusted net earnings from operations fluctuated over the past three years, primarily due to changes in adjusted funds flow from operations, depletion and share-based compensation expense along with associated fluctuations in deferred tax expense (recovery).

Summary of Quarterly Results

	2024				2023			
($ millions, except per share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and gas sales from continuing operations	**1,034.1**	992.9	1,136.4	1,107.9	946.7	998.7	791.6	762.0
Total oil and gas sales	**1,034.1**	992.9	1,136.4	1,107.9	1,012.4	1,236.3	949.6	913.6
Average daily production from continuing operations								
Crude oil and condensate (bbls/d)	**103,885**	102,373	110,399	113,607	96,144	92,824	84,944	78,191
NGLs (bbls/d)	**17,165**	16,859	17,041	19,077	16,023	16,119	14,360	13,562
Natural gas (mcf/d)	**406,027**	393,582	391,249	395,204	248,306	244,777	192,964	157,690
Production from continuing operations (boe/d)	**188,721**	184,829	192,648	198,551	153,551	149,739	131,465	118,035
Total average daily production (boe/d)	**188,721**	184,829	192,648	198,551	162,269	180,581	155,031	139,280
Net income (loss) from continuing operations	**144.7**	277.2	260.9	(398.9)	302.6	133.6	178.4	184.8
Net income (loss) per share from continuing operations - diluted	**0.24**	0.45	0.42	(0.64)	0.54	0.25	0.33	0.33
Net income (loss)	**146.8**	277.2	261.0	(411.7)	951.2	(809.9)	212.3	216.7
Net income (loss) per share – diluted	**0.24**	0.45	0.42	(0.66)	1.70	(1.52)	0.39	0.39
Adjusted net earnings from continuing operations [(1)]	**247.0**	177.0	237.8	187.0	210.0	226.6	171.6	187.7
Adjusted net earnings from continuing operations per share – diluted [(1)]	**0.40**	0.29	0.38	0.30	0.37	0.42	0.32	0.34
Adjusted net earnings from operations [(1)]	**247.0**	177.0	237.8	187.0	192.8	315.5	205.4	218.9
Adjusted net earnings from operations per share – diluted [(1)]	**0.40**	0.29	0.38	0.30	0.34	0.59	0.38	0.40
Cash flow from operating activities from continuing operations	**513.1**	561.7	625.8	411.2	524.0	537.1	365.9	369.8
Cash flow from operating activities	**513.1**	561.7	625.8	411.2	611.3	648.9	462.1	473.4
Adjusted funds flow from continuing operations [(1)]	**619.6**	548.3	611.7	568.2	535.1	548.6	453.4	438.6
Adjusted funds flow from operations [(1)]	**619.6**	548.3	611.7	568.2	574.5	687.1	552.6	524.9
Adjusted working capital deficiency [(1)]	**(90.9)**	(190.4)	(140.4)	(82.0)	(196.3)	(45.7)	(82.5)	(79.9)
Total assets	**11,751.0**	11,511.9	11,336.4	12,035.5	12,775.7	10,371.0	11,277.2	9,759.6
Total liabilities	**4,990.0**	4,793.7	4,811.5	5,659.6	5,908.2	4,660.6	4,597.5	3,113.8
Net debt [(1)]	**2,477.9**	2,959.4	2,962.7	3,582.9	3,738.1	2,876.2	3,000.7	1,436.3
Weighted average shares – diluted (millions)	**615.8**	617.5	620.3	622.6	559.1	536.9	545.3	552.7
Total capital acquisitions [(1)]	**6.0**	26.4	—	—	2,513.9	1.1	1,702.7	372.0
Total capital dispositions [(1)]	**(389.4)**	(1.4)	(541.1)	(105.8)	(602.4)	(0.2)	(8.4)	(2.6)
Development capital expenditures from continuing operations [(1)]	**363.0**	395.9	350.6	398.6	276.0	260.4	123.5	185.0
Development capital expenditures [(1)]	**363.0**	395.9	350.6	398.6	278.9	315.5	230.1	314.2
Dividends declared	**70.7**	70.9	71.7	71.3	68.3	71.7	54.8	17.1
Dividends declared per share	**0.115**	0.115	0.115	0.115	0.120	0.135	0.100	0.032

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

Over the past eight quarters, the Company's oil and gas sales have fluctuated due to volatility in the crude oil, condensate and natural gas benchmark prices, changes in production and fluctuations in corporate oil price differentials. The Company's production has fluctuated due to changes in its development capital spending levels, acquisitions and dispositions and natural declines.

Net income (loss) has fluctuated over the past eight quarters, primarily due to changes in PP&E impairment charges and reversals, changes in adjusted funds flow from operations, unrealized derivative gains and losses, which fluctuate with changes in forward market prices and foreign exchange rates, gains and losses on capital dispositions, and fluctuations in deferred tax expense.

Adjusted net earnings from operations has fluctuated over the past eight quarters, primarily due to changes in adjusted funds flow from operations, depletion and share-based compensation expense along with associated fluctuations in deferred tax expense.

Development capital expenditures have also fluctuated throughout this period due to the timing of acquisitions, dispositions and changes in the Company's development capital spending levels which vary based on a number of factors, including the prevailing commodity price environment.

Fourth Quarter 2024 Review

- Veren's total production averaged 188,721 boe/d in the fourth quarter of 2024, weighted 64 percent towards crude oil and liquids.
- Adjusted funds flow from operations totaled $619.6 million in the fourth quarter of 2024, a 13 percent increase from $548.3 million in the third quarter of 2024. The increase in adjusted funds flow was primarily due to higher production levels.
- During the fourth quarter of 2024, the Company spent $300.4 million on drilling and development activities, drilling 47 (41.9 net) wells. Veren also spent $62.6 million on facilities and seismic, for total development capital expenditures of $363.0 million.
- Net debt decreased by $481.5 million in the fourth quarter of 2024 to $2.48 billion or 1.1 times trailing adjusted funds flow from operations. The decrease was primarily due to proceeds from the Alberta Montney infrastructure transaction and excess cash flow generation.

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P"), as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Veren evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that Veren's DC&P were effective as at December 31, 2024.

Internal Controls over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 and as defined in Canada by National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*, includes those policies and procedures that:

1. pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Veren;
2. are designed to 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 Veren are being made in accordance with authorizations of management and Directors of Veren; and
3. are designed to 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 annual financial statements or interim financial reports.

Management is responsible for establishing and maintaining ICFR for Veren. They have, as at the financial year ended December 31, 2024, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Veren's officers used to design the Company's ICFR is the *Internal Control-Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Under the supervision of Management, Veren conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2024 based on the COSO Framework. Based on this evaluation, Management concluded that as of December 31, 2024, Veren maintained effective ICFR.

The effectiveness of Veren's ICFR as of December 31, 2024 was audited by PricewaterhouseCoopers LLP, as reflected in their report accompanying the Company's financial statements for the year ended December 31, 2024. There were no changes in Veren's ICFR during the year ended December 31, 2024 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

It should be noted that while Veren's officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P and ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

Guidance

Veren's guidance for 2025 is as follows:

Total Annual Average Production (boe/d) [1]	188,000 - 196,000
Development Capital Expenditures ($ millions) [2] [3]	$1,475 - $1,575
Other Information	
Annual operating expenses ($/boe)	$12.75 - $13.75
Royalties	10.75% - 11.75%

(1) Total annual average production (boe/d) is comprised of approximately 65% Oil, Condensate & NGLs and 35% Natural Gas.

(2) Specified financial measures that does not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other entities. Refer to the *Specified Financial Measures* section in this MD&A for further information.

(3) Excludes capitalized administration of approximately $40.0 million, in addition to land expenditures and net property acquisitions and dispositions. Development capital expenditures spend is allocated on an approximate basis as follows: 85% drilling & development and 15% facilities & seismic.

Return of Capital Outlook

Base Dividend	
Current quarterly base dividend per share	$0.115
Total Return of Capital	
% of excess cash flow [1]	60%

(1) Total return of capital is based on a framework that targets to return to shareholders 60% of excess cash flow on an annual basis. Refer to the *Specified Financial Measures* section in this MD&A for further information on base dividends and excess cash flow.

Additional information relating to Veren, including the Company's December 31, 2024 AIF, which along with other relevant documents are available on SEDAR+ at www.sedarplus.ca. Additionally, our AIF forms part of our Form 40-F that is filed with the SEC and is available on EDGAR at www.sec.gov.

Specified Financial Measures

Throughout this MD&A, the Company uses the terms “total operating netback”, "total netback”, "operating netback", "netback", “adjusted funds flow from operations” (or "adjusted FFO"), “adjusted funds flow from continuing operations”, “adjusted funds flow from discontinued operations”, "excess cash flow", "base dividends", "total return of capital", "adjusted working capital surplus (deficiency)", “net debt”, “enterprise value”, “net debt to adjusted funds flow from operations”, "net debt as a percentage of enterprise value", “adjusted net earnings from operations”, “adjusted net earnings from continuing operations”, “adjusted net earnings from continuing operations per share – diluted”, “adjusted net earnings from discontinued operations”, “adjusted net earnings from discontinued operations per share – diluted”, “adjusted net earnings from operations per share - diluted”, "development capital expenditures", "development capital expenditures from continuing operations", "development capital expenditures from discontinued operations", "total capital acquisitions", "total capital dispositions", "net general and administrative expenses" and "net general and administrative expenses per boe". These terms do not have any standardized meaning as prescribed by the International Accounting Standards Board and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Total operating netback and total netback are historical non-GAAP financial measures. Total operating netback is calculated as oil and gas sales, less royalties, operating and transportation expenses. Total netback is calculated as total operating netback plus realized commodity derivative gains and losses. Total operating netback and total netback are common metrics used in the oil and gas industry and are used to measure operating results to better analyze performance against prior periods on a comparable basis. The most directly comparable financial measure to total operating netback and total netback is oil and gas sales.

The following table reconciles oil and gas sales to total operating netback and total netback:

($ millions)	**2024**	2023	% Change
Oil and gas sales	**4,271.3**	3,499.0	22
Royalties	**(441.7)**	(375.3)	18
Operating expenses	**(941.4)**	(770.5)	22
Transportation expenses	**(311.5)**	(174.3)	79
Total operating netback	**2,576.7**	2,178.9	18
Realized gain on commodity derivatives	**71.8**	15.5	363
Total netback	**2,648.5**	2,194.4	21

Operating netback and netback are non-GAAP ratios and are calculated as total operating netback and total netback, respectively, divided by total production. Operating netback and netback are common metrics used in the oil and gas industry and are used to measure operating results on a per boe basis.

Base dividends is a historical non-GAAP financial measure and is calculated as dividends declared less special dividends declared as part of the Company’s return of capital framework and adjusted for timing of the dividend record date. Base dividends are based on a framework that targets dividend sustainability at lower commodity prices, allows for flexibility in the capital allocation process and dividend growth over time, and assists in determining the additional return of capital to shareholders as part of the Company’s return of capital framework.

Total return of capital is a supplementary financial measure and is comprised of base dividends, special dividends and share repurchases, adjusted for the timing of special dividend payments.

Adjusted funds flow from operations is a capital management measure and is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures funded by the Company. Transaction costs are excluded as they vary based on the Company's acquisition and disposition activity and to ensure that this metric is more comparable between periods. Decommissioning expenditures are discretionary and are excluded as they may vary based on the development stage of the Company's assets and operating areas. The most directly comparable financial measure to adjusted funds flow from operations is cash flow from operating activities. Adjusted funds flow from operations is a key measure that assesses the ability of the Company to finance dividends, potential share repurchases, operating activities, capital expenditures and debt repayments. Adjusted funds flow from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS. See Note 19 - "Capital Management" in the audited consolidated financial statements for the year ended December 31, 2024, for additional information on the Company's capital management.

Excess cash flow is a historical non-GAAP financial measure and is defined as adjusted funds flow from operations less development capital and other expenditures, payments on principal portion of lease liability, decommissioning expenditures funded by the Company, unrealized gains and losses on equity derivative contracts, transaction costs and other items (excluding net acquisitions and dispositions). The most directly comparable financial measure to excess cash flow disclosed in the Company's financial statements is cash flow from operating activities. Excess cash flow is a key measure that assesses the ability of the Company to finance dividends, potential share repurchases, debt repayments and returns-based growth.

The following table reconciles cash flow from operating activities to adjusted funds flow from operations and excess cash flow:

($ millions)	**2024**	2023	% Change
Cash flow from operating activities	**2,111.8**	2,195.7	(4)
Changes in non-cash working capital	**175.6**	54.9	220
Transaction costs	**19.8**	48.5	(59)
Decommissioning expenditures [1]	**40.6**	40.0	2
Adjusted funds flow from operations	**2,347.8**	2,339.1	—
Development capital and other expenditures	**(1,587.8)**	(1,220.5)	30
Payments on principal portion of lease liability	**(41.0)**	(20.8)	97
Decommissioning expenditures	**(40.6)**	(40.0)	2
Unrealized loss on equity derivative contracts	**(9.3)**	(29.3)	(68)
Transaction costs	**(19.8)**	(48.5)	(59)
Other items [2]	**(7.7)**	1.6	(581)
Excess cash flow	**641.6**	981.6	(35)

(1) Excludes amounts received from government grant programs.

(2) Other items exclude net acquisitions and dispositions.

The following table reconciles cash flow from operating activities from discontinued operations to adjusted funds flow from discontinued operations:

($ millions)	**2024**	2023	% Change
Cash flow from operating activities from discontinued operations	**—**	399.0	(100)
Changes in non-cash working capital	**—**	(44.6)	(100)
Transaction costs	**—**	8.7	(100)
Decommissioning expenditures [1]	**—**	0.4	(100)
Adjusted funds flow from discontinued operations	**—**	363.5	(100)

(1) Excludes amounts received from government grant programs.

The following tables reconcile cash flow from operating activities and adjusted funds flow from operations from continuing and discontinued operations:

($ millions)	**2024**	2023	% Change
Cash flow from operating activities from continuing operations	**2,111.8**	1,796.7	18
Cash flow from operating activities from discontinued operations	**—**	399.0	(100)
Cash flow from operating activities	**2,111.8**	2,195.7	(4)

($ millions)	**2024**	2023	% Change
Adjusted funds flow from continuing operations	**2,347.8**	1,975.6	19
Adjusted funds flow from discontinued operations	**—**	363.5	(100)
Adjusted funds flow from operations	**2,347.8**	2,339.1	—

Adjusted working capital surplus (deficiency) is a capital management measure and is calculated as accounts payable and accrued liabilities, dividends payable and long-term compensation liability net of equity derivative contracts, less cash, accounts receivable, prepaids and deposits and deferred consideration receivable. Deferred consideration receivable was incurred in 2023 and 2024 through capital dispositions and is included in "other current assets" and "other long-term assets" on the balance sheet. Adjusted working capital surplus (deficiency) is a component of net debt and is a measure of the Company's liquidity.

The following table reconciles adjusted working capital deficiency:

($ millions)	**December 31, 2024**	December 31, 2023	% Change
Accounts payable and accrued liabilities	**493.5**	634.9	(22)
Dividends payable	**70.7**	56.8	24
Long-term compensation liability [1]	**47.4**	66.8	(29)
Cash	**(17.1)**	(17.3)	(1)
Accounts receivable	**(386.5)**	(377.9)	2
Prepaids and deposits	**(99.1)**	(87.8)	13
Deferred consideration receivable [2]	**(18.0)**	(79.2)	(77)
Adjusted working capital deficiency	**90.9**	196.3	(54)

(1) Includes current portion of long-term compensation liability and is net of equity derivative contracts.

(2) Deferred consideration receivable is comprised of $7.2 million included in other current assets and $10.8 million included in other long-term assets (December 31, 2023 - $79.2 million in other current assets and nil in other long-term assets).

Net debt is a capital management measure and is calculated as long-term debt plus adjusted working capital deficiency, excluding the unrealized foreign exchange on translation of hedged US dollar long-term debt. The most directly comparable financial measure to net debt disclosed in the Company's financial statements is long-term debt. Net debt is a key measure of the Company's liquidity.

The following table reconciles long-term debt to net debt:

($ millions)	**December 31, 2024**	December 31, 2023	% Change
Long-term debt [(1)]	**2,454.5**	3,566.3	(31)
Adjusted working capital deficiency	**90.9**	196.3	(54)
Unrealized foreign exchange on translation of hedged US dollar long-term debt	**(67.5)**	(24.5)	176
Net debt	**2,477.9**	3,738.1	(34)

(1) Includes current portion of long-term debt.

Enterprise value is a supplementary financial measure and is calculated as market capitalization plus net debt. Enterprise value is used to assess the valuation of the Company. Refer to the *Liquidity and Capital Resources* section in this MD&A for further information.

Net debt to adjusted funds flow from operations is a capital management measure and is calculated as the period end net debt divided by the sum of adjusted funds flow from operations for the trailing four quarters. Net debt as a percentage of enterprise value is a supplementary financial measure and is calculated as net debt divided by enterprise value. The measures of net debt to adjusted funds flow from operations and net debt as a percentage of enterprise value are used to measure the Company's overall debt position and to measure the strength of the Company's balance sheet. Veren monitors these measures and uses them as key measures in capital allocation decisions including capital spending levels, returns to shareholders including dividends and share repurchases, and financial considerations.

Adjusted net earnings from operations is a historical non-GAAP financial measure and is calculated based on net income (loss) before amortization of E&E undeveloped land, impairment or impairment reversals, unrealized derivative gains or losses, unrealized foreign exchange gain or loss on translation of hedged US dollar long-term debt, gains or losses on capital acquisitions and dispositions, cumulative foreign currency translation of discontinued foreign operations, and deferred tax related to these adjustments. Adjusted net earnings from operations is a key measure of financial performance that is more comparable between periods. The most directly comparable financial measure to adjusted net earnings from operations disclosed in the Company's financial statements is net income (loss).

The following table reconciles net income to adjusted net earnings from operations:

($ millions)	**2024**	2023	% Change
Net income	**273.3**	570.3	(52)
Amortization of E&E undeveloped land	**122.6**	30.9	297
Impairment	**512.3**	822.2	(38)
Unrealized derivative losses	**55.4**	56.9	(3)
Unrealized foreign exchange (gain) loss on translation of hedged US dollar long-term debt	**51.7**	(168.6)	(131)
Net loss on capital dispositions	**21.3**	9.6	122
Reclassification of cumulative foreign currency translation of discontinued foreign operations	**(0.5)**	(621.7)	(100)
Deferred tax adjustments	**(187.3)**	233.0	(180)
Adjusted net earnings from operations	**848.8**	932.6	(9)

The following table reconciles net income (loss) from discontinued operations to adjusted net earnings from discontinued operations:

($ millions)	**2024**	2023	% Change
Net income (loss) from discontinued operations	**(10.6)**	(229.1)	(95)
Impairment	**—**	728.4	(100)
Unrealized derivative losses	**—**	18.9	(100)
Net loss on capital dispositions	**11.1**	9.0	23
Reclassification of cumulative foreign currency translation of discontinued foreign operations	**(0.5)**	(621.7)	(100)
Deferred tax adjustments	**—**	231.2	(100)
Adjusted net earnings from discontinued operations	**—**	136.7	(100)

The following table reconciles adjusted net earnings from continuing and discontinued operations:

($ millions)	**2024**	2023	% Change
Adjusted net earnings from continuing operations	**848.8**	795.9	7
Adjusted net earnings from discontinued operations	**—**	136.7	(100)
Adjusted net earnings from operations	**848.8**	932.6	(9)

Adjusted net earnings from operations per share - diluted is a non-GAAP ratio and is calculated as adjusted net earnings from operations divided by the number of weighted average diluted shares outstanding. Adjusted net earnings from operations presents a measure of financial performance that is more comparable between periods. Adjusted net earnings from operations as presented is not intended to represent net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles development capital and other expenditures to development capital expenditures:

($ millions)	**2024**	2023	% Change
Development capital and other expenditures	**1,587.8**	1,220.5	30
Payments on drilling rig lease liabilities	**12.9**	—	100
Land expenditures	**(41.8)**	(33.6)	24
Capitalized administration [(1)]	**(45.1)**	(42.3)	7
Corporate assets	**(5.7)**	(5.9)	(3)
Development capital expenditures	**1,508.1**	1,138.7	32

(1) Capitalized administration excludes capitalized equity-settled SBC.

Development capital expenditures is a historical non-GAAP financial measure that presents total budgeted development capital spending under the Company's guidance. The most directly comparable financial measure disclosed in the Company's financial statements is development capital and other expenditures on the consolidated statements of cash flows. Development capital expenditures is calculated as development capital and other expenditures plus payments on drilling rig lease liabilities, and excludes land expenditures, capitalized administration and corporate assets. These drilling rig contracts are accounted for in accordance with IFRS 16 *Leases*.

The following table reconciles capital acquisitions, net of cash acquired to total capital acquisitions:

($ millions)	**2024**	2023	% Change
Capital acquisitions, net of cash acquired	**26.4**	3,616.2	(99)
Common shares issued on capital acquisition	**—**	493.0	(100)
Working capital acquired through capital acquisition	**6.0**	116.7	(95)
Long-term debt acquired through capital acquisition	**—**	363.8	(100)
Total capital acquisitions	**32.4**	4,589.7	(99)

The following table reconciles capital dispositions to total capital dispositions:

($ millions)	**2024**	2023	% Change
Capital dispositions	**(1,037.7)**	(604.5)	72
Working capital disposed through capital disposition	**—**	(9.1)	(100)
Total capital dispositions	**(1,037.7)**	(613.6)	69

Total capital acquisitions and total capital dispositions are historical non-GAAP financial measures. Total capital acquisitions are calculated as capital acquisitions, net of cash acquired plus common shares issued on capital acquisition, working capital acquired through capital acquisition and long-term debt acquired through capital acquisition. Total capital dispositions are calculated as capital dispositions less working capital disposed through capital dispositions. Total capital acquisitions and total capital dispositions present the total consideration, including share consideration and working capital, that are included in corporate acquisitions or dispositions.

Net general and administrative expenses is a historical non-GAAP financial measure. Net general and administrative expenses is calculated as general and administrative expenses less transaction costs. Transaction costs vary based on the Company's acquisition and disposition activity, and are excluded from this measure to ensure comparability of general and administrative expenses between periods. Net general and administrative expenses per boe is a non-GAAP ratio and calculated as net general and administrative expenses divided by total production. Net general and administrative expenses per boe measure financial results on a per boe basis.

Management believes the presentation of the specified financial measures above provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

Forward-Looking Information

Certain statements contained in this management's discussion and analysis constitute forward-looking statements and are based on Veren's beliefs and assumptions based on information available at the time the assumption was made. By its nature, such forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements are effective only as of the date of this MD&A. Veren undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required to do so pursuant to applicable law. For additional information on the Company's guidance, refer to the press release dated October 31, 2024 available on SEDAR+ at www.sedarplus.ca and EDGAR at www.sec.gov.

Any “financial outlook” or “future oriented financial information” in this management’s discussion and analysis, as defined by applicable securities legislation, have been approved by management of Veren. Such financial outlook or future oriented financial information is provided for the purpose of providing information about management’s current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

Certain statements contained in this MD&A, including statements related to Veren's capital expenditures, projected asset growth, view and outlook toward future commodity prices, drilling activity and statements that contain words such as "could", "should", "can", "anticipate", "expect", "believe", "will", "may", “projected”, “sustain”, “continues”, “strategy”, “potential”, “projects”, “grow”, “take advantage”, “estimate” and similar expressions and statements relating to matters that are not historical facts constitute "forward-looking information" within the meaning of applicable Canadian securities legislation. The material assumptions and factors in making these forward-looking statements are disclosed in this MD&A under the headings "Overview", "Commodity Derivatives", “Liquidity and Capital Resources” and “Guidance”.

In particular, forward-looking statements include:

- An investment-grade credit rating
- Veren's approach to proactively manage the risk exposure inherent in movements in the price of crude oil, natural gas, the Company's share price, the US/Cdn dollar exchange rate and interest rates through the use of derivatives with investment-grade counterparties;
- Veren's use of derivatives to reduce the volatility of the selling price of commodities, protect against downward price movements and provide some upside participation during rising prices and how these derivatives provide a measure of stability to cash flow;
- Veren's 2025 production, operating expenses and capital expenditures guidance, and other information forming part of the 2025 guidance;
- The extent and effectiveness of hedges;
- Veren's return of capital outlook including dividend expectations and total return of capital target as a percentage of excess cash flow;
- Generating strong returns and excess cash flow to provide continued returns to shareholders:
- Economic and demand growth outlooks;
- OPEC+ voluntary production cuts;
- The Company's liquidity and financial flexibility;
- The method by which the Company's ongoing working capital requirements are financed;
- Natural gas diversification and pricing;
- NCIB expectations; and
- Estimated undiscounted and uninflated cash flows to settle decommissioning liability.

This information contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, many of which are beyond Veren's control. Such risks and uncertainties include, but are not limited to: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas, decisions or actions of OPEC+ and non-OPEC+ countries in respect of supplies of oil and gas; delays in business operations or delivery of services due to pipeline restrictions, rail blockades, outbreaks, pandemics, and blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced, including, but not limited to, the potential for emissions reductions legislation; uncertainties associated with estimating oil and natural gas reserves; risks and uncertainties related to oil and gas interests and operations on Indigenous lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value and likelihood of acquisitions and dispositions, and exploration and development programs; unexpected geological, technical, drilling, construction, processing and transportation problems; the impacts of drought, wildfires and severe weather events; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions, including uncertainty in the demand for oil and gas and economic activity in general; changes in interest rates and inflation; uncertainties associated with regulatory approvals; geopolitical conflicts, including the Russian invasion of Ukraine and conflict in the Middle East; uncertainty of government policy changes; the impact of the implementation of the Canada-United States-Mexico Agreement; uncertainty regarding the benefits and costs of dispositions; failure to complete acquisitions and dispositions; uncertainties associated with credit facilities and counterparty credit risk; and changes in income tax laws, tariffs, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the control of the Company.

Therefore, Veren's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits or detriments Veren will derive therefrom.

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

Crude oil and condensate, and natural gas information is provided in accordance with the United States Financial Accounting Standards Board Topic 932 - "Extractive Activities - Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS").

The Company files its reserves information under National Instrument 51-101 - "Standards of Disclosure of Oil and Gas Activities" (NI 51-101), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission (“SEC”) requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires Company gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards may be material.

Barrels of oil equivalent (“boe”) may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil and condensate as compared to natural gas is significantly different from the energy equivalency of oil, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Oil and gas metrics such as operating netback and netback do not have standardized meaning and as such may not be reliable, and should not be used to make comparisons.

NI 51-101 includes condensate within the natural gas liquids (NGLs) product type. The Company has disclosed condensate as combined with crude oil and separately from other natural gas liquids in this MD&A since the price of condensate as compared to other natural gas liquids is currently significantly higher and the Company believes that this crude oil and condensate presentation provides a more accurate description of its operations and results therefrom. The Company's aggregate production for the past eight quarters and the references to "natural gas", "crude oil" and "condensate", reported in this MD&A consist of the following product types, as defined in NI 51-101 and using a conversion ratio of 6 mcf : 1 bbl where applicable:

	2024					2023					2022
	Annual	Q4	Q3	Q2	Q1	Annual	Q4	Q3	Q2	Q1	Annual
Light & Medium Crude Oil (bbl/d)	8,637	6,439	7,062	9,653	11,434	12,665	12,198	12,405	13,188	12,879	14,274
Heavy Crude Oil (bbl/d)	1,612	—	—	2,866	3,620	3,818	3,795	3,617	3,857	4,010	4,027
Tight Oil (bbl/d)	69,944	67,177	67,262	72,546	72,849	49,779	56,657	54,605	48,151	39,464	42,134
Total Crude Oil (bbl/d)	80,193	73,616	74,324	85,065	87,903	66,262	72,650	70,627	65,196	56,353	60,435
Condensate (bbl/d)	27,349	30,269	28,049	25,334	25,703	21,825	23,494	22,198	19,747	21,839	18,889
Other (bbl/d)	17,532	17,165	16,859	17,041	19,077	15,026	16,023	16,118	14,361	13,562	13,078
NGLs (bbl/d)	44,881	47,434	44,908	42,375	44,780	36,851	39,517	38,316	34,108	35,401	31,967
Shale Gas (mcf/d)	392,539	403,412	390,322	387,893	388,432	200,514	236,926	232,235	184,105	147,458	117,617
Conventional Natural Gas (mcf/d)	3,995	2,615	3,260	3,357	6,773	10,761	11,380	12,542	8,859	10,233	10,482
Total Natural Gas (mcf/d)	396,534	406,027	393,582	391,250	395,205	211,275	248,306	244,777	192,964	157,691	128,099
Total production from continuing operations (boe/d)	191,163	188,721	184,829	192,648	198,551	138,326	153,551	149,739	131,465	118,036	113,752

	2024					2023					2022
	Annual	Q4	Q3	Q2	Q1	Annual	Q4	Q3	Q2	Q1	Annual
Light & Medium Crude Oil (bbl/d)	8,637	6,439	7,062	9,653	11,434	12,665	12,198	12,405	13,190	12,879	14,274
Heavy Crude Oil (bbl/d)	1,612	—	—	2,866	3,620	3,818	3,795	3,617	3,857	4,010	4,027
Tight Oil (bbl/d)	69,944	67,177	67,262	72,546	72,849	63,906	62,512	75,882	63,812	53,184	53,861
Total Crude Oil (bbl/d)	80,193	73,616	74,324	85,065	87,903	80,389	78,505	91,904	80,859	70,073	72,162
Condensate (bbl/d)	27,349	30,269	28,049	25,334	25,703	22,517	23,846	23,094	20,488	22,621	19,518
Other (bbl/d)	17,532	17,165	16,859	17,041	19,077	19,017	17,527	21,634	18,911	17,971	17,038
NGLs (bbl/d)	44,881	47,434	44,908	42,375	44,780	41,534	41,373	44,728	39,399	40,592	36,556
Shale Gas (mcf/d)	392,539	403,412	390,322	387,893	388,432	214,165	242,965	251,152	199,781	161,459	130,902
Conventional Natural Gas (mcf/d)	3,995	2,615	3,260	3,357	6,773	10,761	11,380	12,542	8,859	10,233	10,482
Total Natural Gas (mcf/d)	396,534	406,027	393,582	391,250	395,205	224,926	254,345	263,694	208,640	171,692	141,384
Total average daily production (boe/d)	191,163	188,721	184,829	192,648	198,551	159,411	162,269	180,581	155,031	139,280	132,282

Directors

Barbara Munroe, Chair [6]

Corey Bieber [1] [5]

James Craddock [2] [3] [5]

John Dielwart [3] [4]

Mike Jackson [1] [5]

Jennifer Koury [2] [5]

Jodi Jenson Labrie [1] [2]

François Langlois [1] [3] [4]

Myron Stadnyk [1] [2] [4]

Mindy Wight [2]

Craig Bryksa [4]

[1] Member of the Audit Committee of the Board of Directors

[2] Member of the Human Resources and Compensation Committee of the Board of Directors

[3] Member of the Reserves Committee of the Board of Directors

[4] Member of the Environment, Safety and Sustainability Committee of the Board of Directors

[5] Member of the Corporate Governance and Nominating Committee

[6] Chair of the Board serves in an *ex officio* capacity on each Committee

Officers

Craig Bryksa
President and Chief Executive Officer

Ken Lamont
Chief Financial Officer

Ryan Gritzfeldt
Chief Operating Officer

Mark Eade
Senior Vice President, General Counsel and Corporate Secretary

Justin Foraie
Senior Vice President, Operations and Marketing

Garret Holt
Senior Vice President, Strategy and Planning

Michael Politeski
Senior Vice President, Finance and Treasurer

Shelly Witwer
Senior Vice President, Business Development

Head Office

Suite 2000, 585 - 8th Avenue S.W.
Calgary, Alberta T2P 1G1
Tel: (403) 693-0020
Fax: (403) 693-0070
Toll Free: (888) 693-0020

Banker

The Bank of Nova Scotia
Calgary, Alberta

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

Norton Rose Fulbright Canada LLP
Calgary, Alberta

Evaluation Engineers

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Registrar and Transfer Agent

Investors are encouraged to contact Veren's Registrar and Transfer Agent for information regarding their security holdings:

Computershare Trust Company of Canada
600, 530 - 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Tel: (403) 267-6800

Stock Exchanges

Toronto Stock Exchange - TSX
New York Stock Exchange - NYSE

Stock Symbol

VRN

Investor Contacts

Sarfraz Somani
Manager, Investor Relations
(403) 693-0020

Exhibit 99.4

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Craig Bryksa, certify that:

1. I have reviewed this annual report of Veren Inc. on Form 40-F;
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 period presented in this report;
4. The issuer's other certifying officer 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 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 27, 2025

VEREN INC.

/s/ Craig Bryksa

Name: Craig Bryksa
Title: President and Chief Executive Officer

Exhibit 99.5

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Ken Lamont, certify that:

1. I have reviewed this annual report of Veren Inc. on Form 40-F;
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 period presented in this report;
4. The issuer's other certifying officer 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 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 27, 2025

VEREN INC.

/s/ Ken Lamont

Name: Ken Lamont
Title: Chief Financial Officer

Exhibit 99.6

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 Veren Inc. (the "Company") on Form 40-F for the fiscal year ended December 31, 2024, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Craig Bryksa, 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 27, 2025

VEREN INC.

/s/ Craig Bryksa

Name: Craig Bryksa
Title: President and Chief Executive 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 Veren Inc. (the "Company") on Form 40-F for the fiscal year ended December 31, 2024, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ken Lamont, 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 27, 2025

VEREN INC.

/s/ Ken Lamont

Name: Ken Lamont
Title: Chief Financial Officer

Exhibit 99.8



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, 2024 of Veren Inc. of our report dated February 26, 2025, relating to the consolidated financial statements and the effectiveness of internal control over financial reporting, which appears in the Exhibit incorporated by reference in 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. 333-275312) as amended, Form S-8 (File No. 333-226210) and Form F-3D (File No. 333-205592) of Veren Inc. of our report dated February 26, 2025 referred to above. We also consent to reference to us under the heading “Interests of Experts” in the Annual Information Form, filed as the Exhibit incorporated by reference in this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statements.

/s/PricewaterhouseCoopers LLP

Calgary, Alberta
Canada
February 26, 2025

Exhibit 99.9

CONSENT OF INDEPENDENT PETROLEUM ENGINEER

We hereby consent to the use of and reference to our name and report evaluating the petroleum and natural gas reserves attributable to Veren Inc.'s (the "Company") and its affiliates, including estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, estimated using forecast prices and costs, and the information derived from our reports entitled "Veren Inc., Evaluation of Petroleum Reserves, Based on Forecast Prices and Costs, As at December 31, 2024, dated January 20, 2025", and our report "Veren Inc., Evaluation of Petroleum Reserves, Based on Constant Prices and Costs, As at December 31, 2024, dated January 20, 2025" as described or incorporated by reference in the Company's annual report on Form 40-F for the year ended December 31, 2024 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.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2024 dated February 26, 2025, and that we have no reason to believe that there are any misrepresentations in the information contained therein that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

McDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ Michael Verney
Michael Verney, P.Eng.
Executive Vice President

Calgary, Alberta
February 26, 2025

Exhibit 99.10

Veren Inc.
Supplemental Disclosures about Extractive Activities - Oil & Gas (unaudited)
December 31, 2024

The following disclosures have been prepared by Veren Inc. ("Veren" or the "Company") in accordance with Accounting Standards Codification 932 "Extractive Activities — Oil & Gas" ("ASC 932") issued by the Financial Accounting Standards Board ("FASB") and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS").

For the years ended December 31, 2024 and 2023, the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission ("SEC") requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using trailing 12-month average prices and current costs; whereas NI 51-101 requires Company gross reserves, before royalties, using forecast pricing and costs. The difference between the reported numbers under the two disclosure standards can, therefore, be material.

Petroleum and Natural Gas Reserve Information

Reserves are estimated quantities of crude oil, NGLs and natural gas anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and considered to be economic at average commodity prices based upon the prior 12-month period. Estimates of petroleum and natural gas reserves are very complex, subject to uncertainty, require significant subjective decisions in the evaluation of all available geological, engineering and economic data, and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change. Net reserves presented in this section represent the Company's working interest and overriding royalty share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.

Proved petroleum and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids ("NGL") that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed petroleum and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, which may require future expenditures. Additional future expenditures would be minor compared to the cost of drilling a new well.

Proved undeveloped petroleum and natural gas reserves are reserves that are expected to be recovered from known accumulations where significant future expenditure is required.

Future fluctuations in prices and costs, production rates or changes in political or regulatory environments could cause the Company's reserves to be materially different from that presented.

The changes in Veren's net proved crude oil, NGL and natural gas reserves under constant prices and costs for the two-year period ended December 31, 2024 were as follows:

	Canada				United States				Total			
Net Proved Reserves [1]	**Crude Oil (Mbbls)**	**NGLs (Mbbls)**	**Natural Gas (MMcf)**	**Total (Mboe)**	**Crude Oil (Mbbls)**	**NGLs (Mbbls)**	**Natural Gas (MMcf)**	**Total (Mboe)**	**Crude Oil (Mbbls)**	**NGLs (Mbbls)**	**Natural Gas (MMcf)**	**Total (Mboe)**
December 31, 2022	203,534	117,380	481,118	401,100	26,421	9,581	30,417	41,072	229,955	126,961	511,535	442,172
Revisions of previous estimates	(5,471)	9,919	73,095	16,631	—	—	—	—	(5,471)	9,919	73,095	16,631
Improved recovery	—	—	—	—	—	—	—	—	—	—	—	—
Purchases of reserves in place	91,389	45,791	1,021,291	307,395	—	—	—	—	91,389	45,791	1,021,291	307,395
Extensions and discoveries	4,088	1,675	6,559	6,855	—	—	—	—	4,088	1,675	6,559	6,855
Production	(19,621)	(10,378)	(47,062)	(37,843)	(3,477)	(1,367)	(3,948)	(5,502)	(23,098)	(11,745)	(51,010)	(43,345)
Sales of reserves in place	(1,187)	(114)	(2,217)	(1,670)	(22,944)	(8,215)	(26,469)	(35,570)	(24,131)	(8,328)	(28,685)	(37,240)
December 31, 2023	272,731	164,273	1,532,785	692,468	—	—	—	—	272,731	164,273	1,532,785	692,468
Revisions of previous estimates	2,222	(572)	(19,713)	(1,636)	—	—	—	—	2,222	(572)	(19,713)	(1,636)
Improved recovery	—	—	—	—	—	—	—	—	—	—	—	—
Purchases of reserves in place	502	121	3,718	1,243	—	—	—	—	502	121	3,718	1,243
Extensions and discoveries	28,372	19,085	269,673	92,403	—	—	—	—	28,372	19,085	269,673	92,403
Production	(26,122)	(14,573)	(159,391)	(67,260)	—	—	—	—	(26,122)	(14,573)	(159,391)	(67,260)
Sales of reserves in place	(50,132)	(7,681)	(33,746)	(63,437)	—	—	—	—	(50,132)	(7,681)	(33,746)	(63,437)
December 31, 2024	227,574	160,653	1,593,326	653,781	—	—	—	—	227,574	160,653	1,593,326	653,781
Net Proved Developed Reserves												
December 31, 2022	156,630	62,226	277,787	265,154	16,602	6,782	21,531	26,973	173,232	69,009	299,318	292,127
December 31, 2023	171,093	71,275	632,104	347,719	—	—	—	—	171,093	71,275	632,104	347,719
December 31, 2024	129,242	65,898	578,851	291,615	—	—	—	—	129,242	65,898	578,851	291,615
Net Proved Undeveloped Reserves												
December 31, 2022	46,904	55,153	203,331	135,946	9,819	2,799	8,886	14,099	56,723	57,952	212,217	150,044
December 31, 2023	101,638	92,998	900,681	344,749	—	—	—	—	101,638	92,998	900,681	344,749
December 31, 2024	98,332	94,755	1,014,475	362,166	—	—	—	—	98,332	94,755	1,014,475	362,166

(1) Numbers may not add due to rounding.

2023

Revisions of previous estimates

In 2023, total proved reserves increased by approximately 28.1 MMboe in Canada, due to development downspacing and higher than original anticipated per area recoveries in the Company's Kaybob Duvernay asset. This was slightly offset by revisions due to decreases in constant pricing for crude oil, natural gas, and NGL constituents at December 31, 2023 compared to December 31, 2022, as well as revisions due to marginally higher operating costs due to inflation.

Purchase of reserves in place

In 2023, the Company purchased 25.2 MMboe gas and NGL constituent volumes within the Kaybob area in Canada. In addition, the Company completed two significant acquisitions in the Montney play consisting of crude oil, natural gas, and NGL constituents totaling 282.0 MMboe.

Sale of reserves in place

In 2023, the Company divested its entire North Dakota Bakken position in the United States.

2024

Extensions and discoveries

In 2024, the Company realized significant reserve extensions of +26.2 MMboe within the Kaybob Duvernay and +63.1 MMboe in the Montney assets in Canada.

Sale of reserves in place

During the year ended December 31, 2024, the Company divested the entire Flat Lake (Southeast Saskatchewan), Battrum (Southwest Saskatchewan), Swan Hills (Alberta) and Southern Alberta properties. A portion of the Shaunavon asset was also disposed of.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Petroleum and Natural Gas Reserves

The following information has been developed utilizing procedures prescribed by ASC 932, as updated by Accounting Standards Update 2010-03 "Oil and Gas Reserve Estimation and Disclosures", and based on crude oil, NGL and natural gas reserve and production volumes estimated by Veren's independent reserves evaluators, McDaniel & Associates Consultants Ltd. The methodology used in calculating our price and cost assumptions for the standardized measure of discounted future net cash flows for reserve estimation is based upon the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period.

Future production and development costs are based on constant price assumptions 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 petroleum and natural gas properties based upon existing laws and regulations. A 10% discount factor was applied to the future net cash flows.

The information contained in the following table should not be considered representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the fair market value of Veren's petroleum and natural gas properties. Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated. The prescribed discount rate of 10% may not appropriately reflect interest rates.

Commodity Pricing	**2024**	**2023**
WTI at Cushing Oklahoma ($US/bbl)	76.32	78.21
Edmonton ($Cdn/bbl)	98.01	100.49
Exchange Rate ($US/$Cdn)	0.7333	0.7405
AECO/NIT Spot ($Cdn/MMBTU)	1.46	2.84
Henry Hub NYMEX ($US/MMBTU)	2.07	2.59

The standardized measure of discounted future net cash flows relating to net proved crude oil, NGL and natural gas reserves are as follows:

December 31, 2024 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Future cash inflows	33,197	—	33,197
Future production costs	(14,064)	—	(14,064)
Future development costs and asset retirement obligations [2]	(7,307)	—	(7,307)
Future income taxes [3]	(1,362)	—	(1,362)
Future net cash flows	10,465	—	10,465
Deduct: 10% annual discount factor for timing of future cash flows	(4,005)	—	(4,005)
Standardized measure of future net cash flows	6,460	—	6,460

(1) Numbers may not add due to rounding.

(2) Asset retirement obligations include the costs related to producing wells, future undeveloped proved locations for which there are reserves assigned, as well as all entities that do not have reserves assigned including facilities and gathering systems.

(3) At December 31, 2024, the Company's Canadian tax pools were approximately $6.8 billion.

December 31, 2023 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Future cash inflows	39,713	—	39,713
Future production costs	(15,379)	—	(15,379)
Future development costs and asset retirement obligations [2]	(7,248)	—	(7,248)
Future income taxes [3]	(2,256)	—	(2,256)
Future net cash flows	14,831	—	14,831
Deduct: 10% annual discount factor for timing of future cash flows	(5,698)	—	(5,698)
Standardized measure of future net cash flows	9,132	—	9,132

(1) Numbers may not add due to rounding.

(2) Asset retirement obligations include the costs related to producing wells, future undeveloped proved locations for which there are reserves assigned, as well as all entities that do not have reserves assigned including facilities and gathering systems.

(3) At December 31, 2023, the Company's Canadian tax pools were approximately $8.3 billion.

Reconciliation of Changes in Standardized Measure of Future Net Cash Flows Discounted at 10% per Year Relating to Proved Petroleum and Natural Gas Reserves

December 31, 2024 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Balance, beginning of year	9,132	—	9,132
Sales, net of production costs and royalties	(2,577)	—	(2,577)
Net change in prices and royalties related to forecast production	(1,730)	—	(1,730)
Development costs incurred during the period	1,535	—	1,535
Changes in estimated future development costs	(513)	—	(513)
Extensions, discoveries and improved recovery, net of related costs	1,118	—	1,118
Technical reserve revisions [2]	111	—	111
Purchases of reserves in place	15	—	15
Sales of reserves in place	(1,090)	—	(1,090)
Accretion of discount	890	—	890
Net change in income taxes	486	—	486
All other changes [3] [4]	(919)	—	(919)
Balance, end of year	6,460	—	6,460

(1) Numbers may not add due to rounding.

(2) Includes change in future net values attributed to infill drilling and technical revisions, which include changes to abandonment obligations and carbon tax assumptions.

(3) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, currency exchange rates and actual prices received in 2024 versus forecast.

(4) Includes incremental operating costs associated with gas processing commitments related to the Montney infrastructure disposition completed in 2024.

December 31, 2023 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Balance, beginning of year	9,490	1,354	10,845
Sales, net of production costs and royalties	(2,179)	(365)	(2,544)
Net change in prices and royalties related to forecast production	(3,844)	—	(3,844)
Development costs incurred during the period	850	296	1,146
Changes in estimated future development costs	(197)	—	(197)
Extensions, discoveries and improved recovery, net of related costs	241	—	241
Technical reserve revisions [2]	155	—	155
Purchases of reserves in place	3,899	—	3,899
Sales of reserves in place	(48)	(1,399)	(1,447)
Accretion of discount	949	113	1,062
Net change in income taxes	512	—	512
All other changes [3]	(695)	—	(695)
Balance, end of year	9,132	—	9,132

(1) Numbers may not add due to rounding.

(2) Includes change in future net values attributed to infill drilling and technical revisions, which include changes to abandonment obligations and carbon tax assumptions.

(3) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, currency exchange rates and actual prices received in 2023 versus forecast.

Capitalized Costs Relating to Petroleum and Natural Gas Producing Activities

As at December 31, 2024 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Proved properties	22,172	—	22,172
Unproved properties	1,213	—	1,213
Total capital costs	23,385	—	23,385
Accumulated depletion, amortization and impairment	(13,196)	—	(13,196)
Net capitalized costs	10,189	—	10,189

As at December 31, 2023 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Proved properties	24,579	2	24,581
Unproved properties	1,578	—	1,578
Total capital costs	26,157	2	26,159
Accumulated depletion, amortization and impairment	(14,873)	—	(14,873)
Net capitalized costs	11,284	2	11,286

Costs Incurred in Petroleum and Natural Gas Property Acquisitions, Exploration and Development Activities

Year ended December 31, 2024 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Property acquisition costs			
Proved properties [2]	17	—	17
Unproved properties	16	—	16
Development costs [3]	1,535	—	1,535
Exploration costs	15	—	15
Total	1,582	—	1,582

(1) Numbers may not add due to rounding.

(2) Excludes disposition proceeds of $1.04 billion for proved properties.

(3) Costs incurred exclude capitalized administration.

Year ended December 31, 2023 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Property acquisition costs [2]			
Proved properties	4,075	—	4,075
Unproved properties	515	—	515
Development costs [3]	850	296	1,146
Exploration costs	27	—	27
Total	5,466	296	5,762

(1) Numbers may not add due to rounding.

(2) Excludes disposition proceeds of $611.7 million and $1.9 million for proved and unproved properties, respectively.

(3) Costs incurred exclude capitalized administration.

Results of Operations From Crude Oil and Natural Gas Producing Activities

Year ended December 31, 2024 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Petroleum and natural gas revenues, net of royalties	3,830	—	3,830
Less:			
Operating expenses	941	—	941
Transportation expenses	312	—	312
Depletion and amortization	1,289	—	1,289
Impairment	512	—	512
Accretion	17	—	17
Operating income	759	—	759
Income tax recovery	—	—	—
Results of operations	759	—	759

Year ended December 31, 2023 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Petroleum and natural gas revenues, net of royalties	3,124	457	3,581
Less:			
Operating expenses	771	80	851
Transportation expenses	174	12	186
Depletion and amortization	871	169	1,040
Impairment	94	728	822
Accretion	22	—	22
Operating income (loss)	1,192	(532)	660
Income tax recovery	1	—	1
Results of operations	1,193	(532)	661