PennWest

The annual information form of Penn West Petroleum Ltd. (the "**Corporation**") for the year ended December 31, 2013 dated March 6, 2014 (the "**Original AIF**") has been amended (the "**Revised AIF**") to: (i) update the disclosure on page 14 under the heading "2014 Capital Expenditure Budget and Production Guidance", the disclosure on page A3-15 under the heading "2014 Capital Budget", the table on page A3-16 titled "Capital Expenditures", and the table on pages A3-17 and 18 titled "Production History", in each case to conform the information to the restated audited consolidated financial statements of the Corporation for the years ended December 31, 2013 and 2012 and the related restated management's discussion and analysis, which have been re-filed on SEDAR; (ii) update the Form 51-101F3 - Report of Management and Directors on Reserves Data and Other Information on Appendix A-1 to reflect the amendments to the information noted in paragraph (i); and (iii) make certain conforming changes resulting from the amendments described in paragraphs (i) and (ii). Other than as noted above, the Revised AIF does not update or restate the information contained in the Original AIF or reflect any events that have occurred after the date of the Original AIF.

PENN WEST PETROLEUM LTD.

Revised Annual Information Form
for the year ended December 31, 2013

September 17, 2014

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following is a glossary of certain terms used in this Annual Information Form.

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

"**Annual Information Form**" means this revised annual information form dated September 17, 2014.

"**Board**" or "**Board of Directors**" means the board of directors of Penn West.

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

"**Corporate Conversion**" means the reorganization of Penn West Trust from a trust to a publicly traded exploration and production corporation, being Penn West, pursuant to a plan of arrangement completed under the ABCA effective January 1, 2011.

"**Engineering Report**" means the report prepared by Sproule dated January 30, 2014 evaluating approximately 75 percent and auditing approximately 25 percent of the crude oil, natural gas and natural gas liquids reserves of Penn West and the net present value of future net revenue attributable to those reserves effective as at December 31, 2013.

"**Form 40-F**" means our Amended Annual Report on Form 40-F for the fiscal year ended December 31, 2013 filed with the SEC.

"**Gross**" or "**gross**" means:

(a) in relation to our interest in production or reserves, our "company gross reserves", which are our working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of ours;

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

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

"**Handbook**" means the Chartered Professional Accountant Canada Handbook, as amended from time to time.

"**IFRS**" means International Financial Reporting Standards, being the standards and interpretations issued by the International Accounting Standards Board, as amended from time to time. The changeover date to IFRS was January 1, 2011 with retrospective adoption from January 1, 2010 onwards. For periods relating to financial years beginning on or after January 1, 2011, Canadian generally accepted accounting principles applicable to publicly accountable enterprises is determined with reference to Part I of the Handbook, which is IFRS.

"**Net**" or "**net**" means:

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

(b) in relation to our interest in wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

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

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

"**Non-Resident**" means: (i) a person who is not a resident of Canada for the purposes of the Tax Act; or (ii) a partnership that is not a Canadian partnership for the purposes of the Tax Act.

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

"**Penn West**", "**we**", "**us**" or "**our**" means: (i) subsequent to the completion of the Corporate Conversion, Penn West Petroleum Ltd., a corporation existing under the ABCA and the successor to Penn West Trust; and (ii) prior to the completion of the Corporate Conversion, Penn West Trust. Where the context requires, these terms also include all of Penn West's Subsidiaries on a consolidated basis.

"**Penn West Trust**" means Penn West Energy Trust, which trust was reorganized into Penn West and terminated pursuant to the Corporate Conversion.

"**SEC**" means the United States Securities and Exchange Commission.

"**Senior Notes**" means our guaranteed, unsecured senior notes consisting of US$1,629 million principal amount of notes, Cdn$175 million principal amount of notes, £77 million principal amount of notes and €10 million principal amount of notes, all as described under the heading "Capitalization of Penn West – Debt Capital – Senior Notes".

"**Shareholders**" means holders of our Common Shares.

"**Sproule**" means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

"**Subsidiaries**" has the meaning ascribed thereto in the *Securities Act* (Ontario) and, for greater certainty, includes all corporations and partnerships owned, controlled or directed, directly or indirectly, by Penn West or Penn West Trust, as the case may be.

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

"**Trust Unit**" means a trust unit of Penn West Trust, all of which were exchanged for Common Shares on a one-for-one basis pursuant to the Corporate Conversion.

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

"**undeveloped land**" and "**unproved property**" each mean a property or part of a property to which no reserves have been specifically attributed.

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

CONVENTIONS

Certain terms used herein are defined in the "Glossary of Terms". Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

All dollar amounts in this document are expressed in Canadian dollars, except where otherwise indicated. References to "**$**" or "**Cdn$**" are to Canadian dollars, references to "**US$**" are to United States dollars, references to "**£**" are to pounds sterling, and references to "**€**" are to Euros. On March 6, 2014, the exchange rate based on the noon rate as reported by the Bank of Canada, was Cdn$1.00 equals US$0.9119.

All financial information herein has been presented in Canadian dollars in accordance with IFRS.

ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	barrel or barrels	GJ	gigajoule
bbl/d	barrels per day	GJ/d	gigajoules per day
Mbbl	thousand barrels	Mcf	thousand cubic feet
MMbbl	million barrels	MMcf	million cubic feet
NGLs	natural gas liquids	Bcf	billion cubic feet
MMboe	million barrels of oil equivalent	Mcf/d	thousand cubic feet per day
Mboe	thousand barrels of oil equivalent	MMcf/d	million cubic feet per day
boe/d	barrels of oil equivalent per day	m^3	cubic metres
		MMbtu	million British thermal units

Other

BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil.
WTI	West Texas Intermediate, the reference price paid in United States dollars at Cushing, Oklahoma for crude oil of standard grade.
API	American Petroleum Institute.
°API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	pounds per square inch.
MM$	million dollars.
MW	megawatt.
MWh	megawatt hour.
CO_2	carbon dioxide.

OIL AND GAS INFORMATION ADVISORIES

Where any disclosure of reserves data is made in this Annual Information Form (including the Appendices hereto) that does not reflect all of the reserves of Penn West, the reader should note that 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.

All production and reserves quantities included in this Annual Information Form (including the Appendices hereto) have been prepared 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 United States companies. Nevertheless, as part of Penn West's Amended Annual Report on Form 40-F for the year ended December 31, 2013 filed with the SEC, Penn West has disclosed proved reserves quantities using the standards contained in SEC Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with the U.S. Financial Accounting Standards Board, "Disclosures About Oil and Gas Producing Activities", which disclosure complies with the SEC's rules for disclosing oil and gas reserves.

References in this Annual Information Form to land and properties held, owned, acquired or disposed by us, or in respect of which we have an interest, refer to land or properties in respect of which we have a lease or other contractual right to explore for, develop, exploit and produce hydrocarbons underlying such land or properties.

BOEs 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 as compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is misleading as an indication of value.

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres	bbl	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.500
gigajoules (at standard)	MMbtu	0.948
MMbtu (at standard)	gigajoules	1.055
gigajoules (at standard)	Mcf	1.055

EFFECTIVE DATE OF INFORMATION

Except where otherwise indicated, the information in this Annual Information Form is presented as at the end of Penn West's most recently completed financial year, being December 31, 2013.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

In the interest of providing our securityholders and potential investors with information regarding Penn West, including management's assessment of Penn West's future plans and operations, certain statements contained and incorporated by reference in this document constitute forward-looking statements or information (collectively "**forward-looking statements**") within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "budget", "may", "will", "project", "could", "plan", "intend", "should", "believe", "outlook", "objective", "aim", "potential", "target" and similar words suggesting future events or future performance. In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and can be profitably produced in the future. In particular, this document and the documents incorporated by reference herein contain, without limitation, forward-looking statements pertaining to the following: our focus on profitability and goals of growing production per share, cash flow per share and strengthening our balance sheet position; our commitment to maximizing the efficiency of our capital programs and the reliability of our production base while growing the oil and liquids weighting of our total production; our belief that our long-term plan to deleverage our balance sheet, continue operational and cost control improvements, and focus on light oil development integrated with waterflood programs concentrated in our Cardium, Slave Point and Viking plays is the best strategy available to maximize Shareholder value; the objective of our long-term plan to provide Shareholders with compound annual per share growth in oil production and funds flow subsequent to a deleveraging period and provide Shareholders with a return through a sustainable dividend; our intention to sell $1.5 to 2.0 billion of non-core assets before 2015 in order to deleverage our balance sheet; the details of the proposed disposition expected to close in mid-March 2014, including the anticipated sale proceeds, the nature of the assets and liabilities to be sold and the closing timing; the details of our 2014 exploration and development capital budget, including the amount thereof and our intention that the majority of the development capital budget will be allocated to light-oil development in the Cardium, Viking and Slave Point plays; our intention that our capital spending program will be more balanced during 2014 than in previous years, resulting in production additions weighted to the second half of 2014; our forecast average daily production for 2014 and the liquids weighting thereof; the details of our ongoing acquisition, disposition, farm-out and financing strategy; our dividend policy, including the amount of dividends that we intend to pay, the proposed timing of such payments, the factors that may affect the amount of dividends that we pay and the anticipated timing of the Board's review of our dividend policy; the effect on the market value of the Common Share should we reduce or suspend the amount of cash dividends that we pay in the future; our expectations regarding the operational and financial impact that climate change regulations in the jurisdictions in which we operate will have on us; our belief that the trend towards heightened and additional standards in environmental legislation and regulation will continue and our expectation that we will be making increased expenditures as a result of the expansion of our operations and the adoption of new legislation relating to the protection of the environment; our assessment of the operational and financial impacts that certain risks factors could have on us and on our dividend policy and the value of our Common Shares should such risk factors materialize; the quantity of our oil, natural gas liquids and natural gas reserves, the recoverability thereof, and the net present values of future net revenue to be derived from our reserves using forecast prices and costs, including the disclosure set forth in Appendix A-3 under "Amended Statement of Reserves Data and Other Oil and Gas Information – Reserves Data"; the amount of royalties, operating costs, development costs, abandonment and reclamation costs and income taxes that we will incur in connection with the production of our reserves; our outlook for oil, natural gas liquids and natural gas prices; our expectations regarding future currency exchange rates and inflation rates; our expectations regarding how we will fund the development costs of our reserves; our expectation that interest and other funding costs will not make the development of any of our properties uneconomic; our expectations regarding the timing for developing our proved undeveloped reserves and probable undeveloped reserves and the amount of future capital expenditures required to develop such reserves; our expectations regarding the significant economic factors and other significant uncertainties that could affect our reserves data; the number of net well bores and facilities and the length of pipeline in respect of which we expect to incur abandonment and reclamation costs and the total amount of such costs that we expect to incur and the timing thereof; the details of our exploration and development plans in each of our Cardium, Slave Point and Viking resource plays in 2014, including our key focus areas within each resource play, the details of our ongoing and proposed waterflood programs, and our pursuit of down spacing opportunities; our belief that recent results in our key plays and continuing advancements in drilling, completions and other technologies will enable us to pursue various enhanced recovery techniques aimed at increasing oil recovery rates in several of our large plays; our plans to continue to expand our existing waterflood projects and initiate others in most of our key areas; the details of our 2014 capital budget, including the amount thereof, our focus on improving capital efficiencies and profitability over short-term production, the total budget for development capital and base infrastructure improvement, the amount of the budget allocated to light-oil development, including the budgets for each of the Cardium, Viking and Slave Point plays, the allocations to longer lead time production projects, including drilling wells in the Cardium and Slave Point areas and making significant investments in waterflood programs in our key areas, and the number of net wells we expect to drill; our expectation regarding when we will be required to pay income taxes; our production volume estimates for 2014; and the nature of, effectiveness of, and benefits to be derived from, our future marketing arrangements and risk management strategies.

With respect to forward-looking statements contained or incorporated by reference in this document, we have made assumptions regarding, among other things: the terms and timing of asset sales completed under our ongoing program to sell between $1.5 billion and $2.0 billion of non-core assets, including the asset sale anticipated to close in the first quarter of 2014; our ability to execute or long-term plan as described herein and the impact that the successful execution of such plan will have on us and our shareholders; the economic returns anticipated from expenditures on our assets; future crude oil, natural gas liquids and natural gas prices and differentials between light, medium and heavy oil prices and Canadian, WTI and world oil and natural gas prices; future capital expenditure levels and capital programs; future crude oil, natural gas liquids and natural gas production levels; the laws and regulations that we will be required to comply with, including laws and regulations relating to taxation, royalty regimes and environmental protection, and the continuance of those laws and regulations; that we will have sufficient cash flow, debt or equity sources or other financial resources required to fund our capital and operating expenditures and requirements as needed; drilling results and the recoverability of our reserves; the estimates of our reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; the amount of royalties, operating costs, development costs, abandonment and reclamation costs and income taxes that we will incur in connection with the production of our reserves; future exchange rates, inflation rates and interest rates; future income tax rates; the amount of tax pools available to us; the amount of future cash dividends that we intend to pay and the level of participation in our dividend reinvestment plan; the cost of expanding our property holdings; our ability to execute our capital programs as planned without significant adverse impacts from various factors beyond our control, including weather, infrastructure access and delays in obtaining regulatory approvals and third party consents; our ability to obtain equipment in a timely manner to carry out development activities and the costs thereof; our ability to market our oil and natural gas successfully to current and new customers; our ability to reduce our exposure to commodity price fluctuations and counterparty risks through our risk management programs; the impact of increasing competition; our ability to obtain financing on acceptable terms, including our ability to renew or replace our credit facility and our ability to finance the repayment of our senior unsecured notes on maturity; that our conduct and results of operations will be consistent with expectations; our ability to add production and reserves through our development and exploitation activities; and that we will have the ability to develop our oil and gas properties in the manner currently contemplated. In addition, many of the forward-looking statements contained or incorporated by reference in this document are located proximate to assumptions that are specific to those forward-looking statements, and such assumptions should be taken into account when reading such forward-looking statements: see in particular the assumptions identified in Appendix A-3 under "Amended Statement of Reserves Data and Other Oil and Gas Information – Reserves Data" and "Amended Statement of Reserves Data and Other Oil and Gas Information – Notes to Reserves Data Tables".

Although Penn West believes that the expectations reflected in the forward-looking statements contained or incorporated by reference in this document, and the assumptions on which such forward-looking statements are made, are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking statements included or incorporated by reference in this document, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause our actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things: the possibility that we are unable to execute some or all of our ongoing non-core asset disposition program on favourable terms or at all, including the disposition discussed herein that is scheduled to close in the first quarter of 2014, whether due to the failure to receive requisite regulatory approvals or satisfy applicable closing conditions or for other reasons that we cannot anticipate; the possibility that we will not be able to successfully execute our long-term plan in part or in full, and the possibility that some or all of the benefits that we anticipate will accrue to us and our securityholders as a result of the successful execution of such plan do not materialize; the impact of weather conditions on seasonal demand; the impact of weather conditions on our ability to execute capital programs; the risk that we will be unable to execute our capital programs as planned without significant adverse impacts from various factors beyond our control, including weather, infrastructure access and delays in obtaining regulatory approvals and third party consents; risks inherent in oil and natural gas operations; uncertainties associated with estimating reserves and resources; competition for, among other things, capital, acquisitions of reserves, resources, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions, including the historical acquisitions discussed herein; geological, technical, drilling and processing problems; general economic and political conditions in Canada, the U.S., Europe and globally, and in particular, the effect that those conditions have on commodity prices and our access to capital; industry conditions, including fluctuations in the price of oil and natural gas, price differentials for crude oil and natural gas produced in Canada as compared to other markets and transportation restrictions, including pipeline and railway capacity constraints; royalties payable in respect of our oil and natural gas production and changes to government royalty frameworks in jurisdictions in which we operate and the impact that such changes may have on us; changes in government regulation of the oil and natural gas industry, including environmental regulation; fluctuations in foreign exchange or interest rates; unanticipated operating events or environmental events that can reduce production or cause production to be shut-in or delayed, including extreme cold during winter months, wild fires and flooding; failure to obtain regulatory, industry partner and other third-party consents and approvals when required, including for acquisitions, dispositions, joint ventures, partnerships and mergers; failure to realize the anticipated benefits of dispositions, acquisitions, joint ventures and partnerships, including the historical dispositions, acquisitions, joint ventures and partnerships discussed herein; changes in taxation and other laws and regulations that affect us and our securityholders; the potential failure of counterparties to honour their contractual obligations; stock market volatility and market valuations; the ability of the Organization of the Petroleum Exporting Countries ("**OPEC**") to control production and balance global supply and demand of crude oil at desired price levels; political uncertainty, including the risks of hostilities, in the petroleum producing regions of the world; delays in exploration and development activities if drilling and related equipment is unavailable or if access to drilling locations is restricted; the impact of pipeline interruptions and apportionments and the actions or inactions of third party operators; and the other factors described under "Risk Factors" in this document and in Penn West's public filings available in Canada at www.sedar.com and in the United States at www.sec.gov. Readers are cautioned that this list of risk factors should not be construed as exhaustive.

The forward-looking statements contained and incorporated by reference in this document speak only as of the date of this document. Except as expressly required by applicable securities laws, Penn West does not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained and incorporated by reference in this document are expressly qualified by this cautionary statement.

GENERAL AND ORGANIZATIONAL STRUCTURE

General

Penn West is a corporation amalgamated under the ABCA. It is the successor to Penn West Trust and commenced operations as such on January 1, 2011. It operates under the trade names "Penn West" and "Penn West Exploration". Penn West's head and registered office is located at Suite 200, 207 – 9th Avenue S.W., Calgary, Alberta, T2P 1K3.

Corporate Conversion

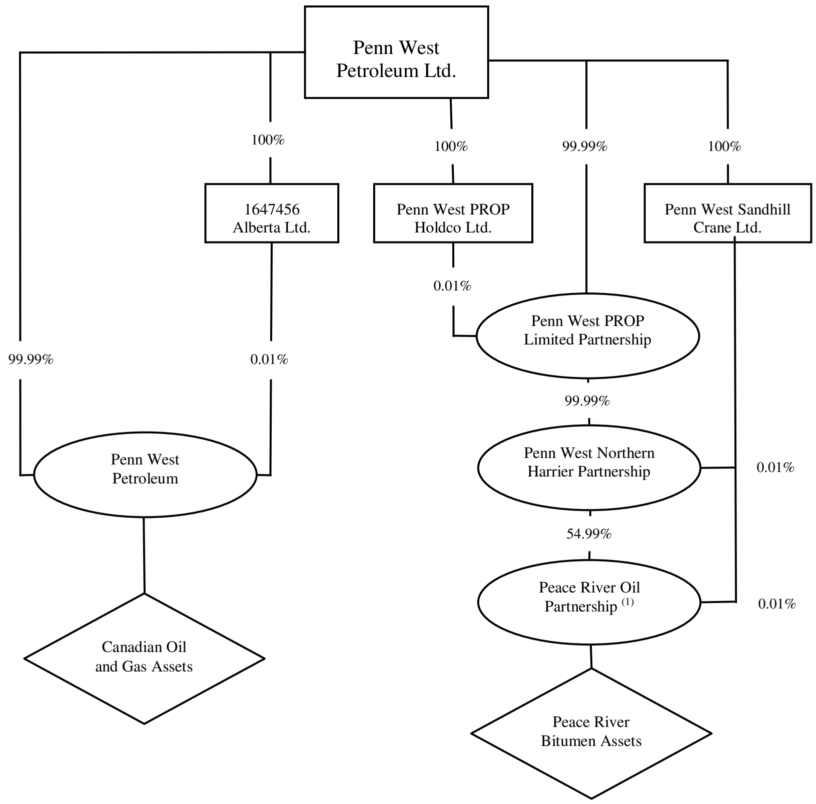
The Corporate Conversion was completed on January 1, 2011 and resulted in the reorganization of Penn West Trust (an income trust) into Penn West (a corporation) and the unitholders of Penn West Trust becoming the Shareholders of Penn West. Penn West and its Subsidiaries now carry on the business formerly carried on by Penn West Trust and its Subsidiaries.

In accordance with the terms of the Corporate Conversion, all of the outstanding Trust Units were exchanged for Common Shares on a one-for-one basis. In addition, as part of the Corporate Conversion, Penn West Trust was dissolved and, through a series of steps, Penn West acquired all of the assets and assumed all of the liabilities of Penn West Trust.

Penn West's Common Shares commenced trading on the TSX under the trading symbol "PWT" on January 10, 2011 and on the NYSE under the trading symbol "PWE" on January 3, 2011.

Our Organizational Structure

The following diagram sets forth the organizational structure of Penn West and its material Subsidiaries as at the date hereof.



Notes:

(1) The remaining 45% interest in Peace River Oil Partnership is owned by Winter Spark Resources, Inc., an affiliate of China Investment Corporation.

(2) Each of the entities identified in the diagram was incorporated, continued, formed or organized, as the case may be, under the laws of the Province of Alberta.

DESCRIPTION OF OUR BUSINESS

Overview

Penn West is one of the largest conventional oil and natural gas producers in Canada. Penn West operates a significant portfolio of opportunities with a dominant position in light oil in Canada. Based in Calgary, Alberta, Penn West operates throughout western Canada on a land base encompassing approximately five million acres. Penn West is a development and production company focused on profitability with goals of growing production per share, cash flow per share and strengthening its balance sheet position. We are committed to maximizing the efficiency of our capital programs and the reliability of our production base while growing the oil and liquids weighting of our total production. As at December 31, 2013, Penn West had approximately 1,415 employees.

Reserves Data

See Appendices A-1, A-2 and A-3 for complete NI 51-101 oil and gas reserves disclosure for Penn West as at December 31, 2013.

General Development of the Business

The following is a description of the general development of Penn West's business over the last three completed financial years.

Year Ended December 31, 2011

Corporate Conversion

The Corporate Conversion was completed on January 1, 2011 and resulted in the reorganization of Penn West Trust (an income trust) into Penn West (a corporation) and the unitholders of Penn West Trust becoming the Shareholders of Penn West. Penn West's Common Shares commenced trading on the TSX under the trading symbol "PWT" on January 10, 2011 and on the NYSE under the trading symbol "PWE" on January 3, 2011.

Convertible Debenture Maturities

On May 31, 2011, Penn West's 7.2% convertible, unsecured, subordinated debentures matured and were settled in cash for a total of approximately $24 million.

On December 31, 2011, Penn West's 6.5% convertible, extendible, unsecured, subordinated debentures matured and were settled in cash for a total of approximately $224 million.

Renewal of Credit Facilities

On June 27, 2011, Penn West renewed its unsecured, revolving credit facility for a four-year term ending June 26, 2015 with a syndicate of Canadian and international banks. The credit facility had an aggregate borrowing limit of $2.25 billion at that time.

Executive Appointments

On August 9, 2011, Bill Andrew retired as Chief Executive Officer and assumed the role of Vice-Chairman of Penn West. Murray Nunns, the President and Chief Operating Officer of Penn West, was appointed President and Chief Executive Officer.

Increase in Borrowing Limit on Credit Facilities

On October 27, 2011, Penn West exercised the "accordion" feature of its credit facility, thereby increasing the borrowing limit on its unsecured, revolving credit facility by $500 million. The credit facility then had an aggregate borrowing limit of $2.75 billion. No other terms of the credit facility, including the rates, terms and maturity date of the additional capacity, were changed.

Private Placement of Notes

On November 30, 2011, Penn West completed the private placement of its Series CC, Series DD, Series EE and Series FF Senior Notes, which consisted of the issuance of US$25 million principal amount of 3.64 percent notes due in 2016, US$12 million principal amount of 4.23 percent notes due in 2018, US$68 million principal amount of 4.79 percent notes due in 2021 and Cdn$30 million principal amount of 4.63 percent notes due in 2018. Each of these Series of Senior Notes are guaranteed, unsecured and rank equally with Penn West's bank credit facilities and its other Senior Notes. The proceeds of the private placement were used to repay a portion of the indebtedness outstanding under Penn West's bank credit facilities.

Aggregate Acquisition and Disposition Activity

Penn West completed non-core property dispositions, net of acquisitions, of approximately $266 million in 2011.

Year Ended December 31, 2012

Renewal of Credit Facilities

On June 15, 2012, Penn West renewed its unsecured, revolving credit facility for a four-year term ending June 30, 2016 with a syndicate of Canadian and international banks. The credit facility now has an aggregate borrowing limit of $3.0 billion.

Aggregate Acquisition and Disposition Activity

Penn West completed non-core property dispositions, net of acquisitions, of approximately $1,627 million in 2012. Total production associated with the combined divestments was approximately 16,500 boe per day. Production was weighted toward oil and liquids. Divested assets were located primarily in Eastern Alberta and Southeast Saskatchewan and represented mature, base assets in Penn West's asset portfolio. The net proceeds of the dispositions were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Year Ended December 31, 2013

Board, Management and Staffing Changes

The Board underwent a renewal process in May 2013 that resulted in John Brussa (Chairman), William Andrew (Vice-Chairman) and Shirley McClellan retiring from the Board and Rick George (Chairman), Allan Markin (Vice-Chairman) and Jay Thornton joining the Board. James Allard, George Brookman, Gillian Denham, Daryl Gilbert, Frank Potter, Jack Schanck and James Smith were re-elected as directors at Penn West's annual general meeting and continued as directors.

In June 2013, Murray Nunns (President and Chief Executive Officer) retired from both his Board and management positions. David Roberts joined Penn West in June 2013 as President and Chief Executive Officer and was added to the Board.

In July 2013, Allan Markin (Vice-Chairman) resigned from the Board.

Penn West streamlined its management structure in July 2013 which resulted in management changes. This led to David Middleton (Executive Vice-President, Operations Engineering and Managing Director, Peace River Oil Partnership), Bob Shepherd (Senior Vice-President, Enhanced Oil Recovery and Cordova Joint Venture) and Rob Wollmann (Senior Vice President, Exploration) leaving Penn West. The new senior management structure consists of David Roberts (President and Chief Executive Officer), Todd Takeyasu (Executive Vice-President and Chief Financial Officer), Mark Fitzgerald (Senior Vice-President, Development), Gregg Gegunde (Senior Vice-President, Production), and Keith Luft (General Counsel and Senior Vice-President, Corporate Services).

In 2013, in an effort to operate in a more efficient manner Penn West reduced its staffing levels by over 25 percent.

Change to Dividend Amount

In June 2013, Penn West announced a change to its dividend amount. Effective for the 2013 third quarter dividend, Penn West reduced its quarterly dividend amount from $0.27 per Common Share to $0.14 per Common Share.

Strategic Alternatives Review

In June 2013, the Board formed a special committee (the "**Special Committee**") to review strategic alternatives to increase Shareholder value. In November 2013, Penn West announced that the review was complete and that the Board, based on recommendations from management, the Special Committee and its financial advisor, had determined that Penn West's long-term plan to deleverage its balance sheet, continue operational and cost control improvements, and focus on light oil development integrated with waterflood programs concentrated in its Cardium, Slave Point and Viking plays was the best strategy available to maximize Shareholder value. Penn West announced that the objective of the long-term plan was to provide Shareholders with compound annual per share growth in oil production and funds flow subsequent to a deleveraging period and provide Shareholders with a return through a sustainable dividend. In furtherance of the plan, Penn West announced its intention to sell $1.5 to 2.0 billion of non-core assets before 2015 in order to deleverage its balance sheet of which $486 million had purchase and sale agreements in place and closed in December 2013.

Aggregate Acquisition and Disposition Activity

Penn West completed non-core property dispositions, net of acquisitions, of approximately $540 million in 2013. Total production associated with the combined divestments was approximately 11,000 boe per day. Divested assets were located primarily in the East Central, North West and Southern areas of Alberta and represented mature, base assets in Penn West's asset portfolio which had minimal capital allocated to them in the long-term plan. The net proceeds of the dispositions were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

2014 Developments

Pending Disposition

In January 2014, Penn West announced that it had entered into an agreement to dispose of non-core assets in the central and southwestern areas of Alberta for total proceeds of $175 million. Average production on these assets was 6,700 boe per day and weighted 58 percent to natural gas and included approximately 1,800 producing or suspended wellbores. The assets do not have any development capital allocated to them in Penn West's long-term plan. The disposition is expected to close in mid-March 2014.

2014 Capital Expenditure Budget and Production Guidance

Penn West's capital budget has been revised from $900 million to $820 million to reflect the reclassification of $80 million of the budget from capital expenditures to operating expenses in connection with the restatement of certain of our historical financial statements as described in our September 18, 2014 press release "Penn West Provides Results of Internal Review of Accounting Practices, Files Restated Financial Statements and Confirms no Impact on Strategic Direction". There was no impact on planned development capital activities for 2014 as a result of this adjustment.

Penn West's capital spending program is anticipated to be more balanced during 2014 than in previous years, resulting in production additions weighted to the second half of 2014. This change in spending profile combined with the dispositions that closed in December 2013 and the disposition described above that is scheduled to close in mid-March 2014 resulted in Penn West forecasting average production for 2014 of between 101,000 and 106,000 boe per day weighted approximately 66 percent to crude oil and NGLs.

Ongoing Acquisition, Disposition, Farm-Out and Financing Activities

Potential Acquisitions

Penn West continues to evaluate potential acquisitions of all types of petroleum and natural gas and other energy-related assets as part of its ongoing asset portfolio management program. At times, Penn West could be in the process of evaluating several potential acquisitions which individually or in the aggregate could be material. As of the date hereof, Penn West has not reached agreement on the price or terms of any potential material acquisitions. Penn West cannot predict whether any current or future opportunities will result in one or more acquisitions for Penn West.

Potential Dispositions and Farm-Outs

Penn West continues to evaluate potential dispositions of its petroleum and natural gas assets as part of its ongoing portfolio asset management program. In particular, Penn West has announced its intention to sell $1.5 to 2.0 billion of non-core assets before 2015. In late 2013, Penn West completed the first phase of its disposition program which resulted in proceeds of $486 million. The second phase of its disposition program began in 2014 with the announcement of a $175 million disposition expected to close in mid-March 2014. In addition, Penn West continues to consider potential farm-out opportunities with other industry participants in respect of its petroleum and natural gas assets in circumstances where Penn West believes it is prudent to do so based on, among other things, its capital program, development plan timelines and the risk profile of such assets. Penn West is normally in the process of evaluating several potential dispositions of its assets and farm-out opportunities at any one time, which individually or in the aggregate could be material. As of the date hereof, Penn West has not reached agreement on the price or terms of any potential material dispositions or farm-outs. Penn West cannot predict whether any current or future opportunities will result in one or more dispositions or farm-outs for Penn West.

Potential Financings

Penn West continuously evaluates its capital structure, liquidity and capital resources, and financing opportunities that arise from time to time. Penn West may in the future complete financings of Common Shares or debt (including debt which may be convertible into Common Shares) for purposes that may include the financing of acquisitions, the financing of Penn West's operations and capital expenditures, and the repayment of indebtedness. As of the date hereof, Penn West has not reached agreement on the pricing or terms of any potential material financing. Penn West cannot predict whether any current or future financing opportunity will result in one or more material financings being completed.

Significant Acquisitions

Penn West did not complete an acquisition during its most recently completed financial year that was a significant acquisition for the purposes of Part 8 of National Instrument 51-102.

CAPITALIZATION OF PENN WEST

Share Capital

The authorized capital of Penn West consists of an unlimited number of Common Shares without nominal or par value and 90,000,000 preferred shares without nominal or par value. A description of the share capital of Penn West is set forth below. This description is a summary only. Shareholders are encouraged to read the full text of such share provisions, which are available on SEDAR at www.sedar.com.

Common Shares

Shareholders are entitled to notice of, to attend and to one vote per Common Share held at any meeting of the shareholders of Penn West (other than meetings of a class or series of shares of Penn West other than the Common Shares).

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

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

As at March 6, 2014, 490,688,948 Common Shares were issued and outstanding.

Preferred Shares

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

As at the date hereof, no preferred shares are issued and outstanding.

Debt Capital

Penn West has issued the Senior Notes and has a syndicated credit facility. A description of the debt capital of Penn West is set forth below. This description is a summary only. Shareholders are encouraged to read the full text of the agreements governing Penn West's Senior Notes and credit facility, which are available on SEDAR at www.sedar.com.

Senior Notes

Penn West has issued the Senior Notes, which consist of US$1,629 million principal amount of notes, Cdn$175 million principal amount of notes, £77 million principal amount of notes and €10 million principal amount of notes. The Senior Notes are guaranteed by Penn West's material subsidiaries, are unsecured and rank equally with our bank credit facilities. The following is a brief summary of certain of the material terms of each series of our Senior Notes.

Series	Currency / Principal Amount	Interest Rate	Issue Date	Maturity Date
Series A	US$160 million	5.68%	May 31, 2007	May 31, 2015
Series B	US$155 million	5.80%	May 31, 2007	May 31, 2017
Series C	US$140 million	5.90%	May 31, 2007	May 31, 2019
Series D	US$20 million	6.05%	May 31, 2007	May 31, 2022
Series E	US$152.5 million	6.12%	May 29, 2008	May 29, 2016
Series F	US$278 million	6.30%	May 29, 2008	May 29, 2018
Series G	US$49.5 million	6.40%	May 29, 2008	May 29, 2020
Series H	Cdn$30 million	6.16%	May 29, 2008	May 29, 2018
Series I	£57 million(1)	7.78%(1)	July 31, 2008	July 31, 2018
Series J	US$50 million	8.29%	May 5, 2009	May 5, 2014
Series K	US$35 million	8.89%	May 5, 2009	May 5, 2016
Series L	US$34 million	9.32%	May 5, 2009	May 5, 2019
Series M	US$30 million	8.89%	May 5, 2009	May 5, 2019(2)
Series N	£20 million(3)	9.49%(3)	May 5, 2009	May 5, 2019
Series O	€10 million(4)	9.52%(4)	May 5, 2009	May 5, 2019
Series P	Cdn$5 million	7.58%	May 5, 2009	May 5, 2014

Series	Currency / Principal Amount	Interest Rate	Issue Date	Maturity Date
Series Q	US$27.5 million	4.53%	March 16, 2010	March 16, 2015
Series R	US$65 million	5.29%	March 16, 2010	March 16, 2017
Series S	US$112.5 million	5.85%	March 16, 2010	March 16, 2020
Series T	US$25 million	5.95%	March 16, 2010	March 16, 2022
Series U	US$20 million	6.10%	March 16, 2010	March 16, 2025
Series V	Cdn$50 million	4.88%	March 16, 2010	March 16, 2015
Series W	US$18 million	4.17%	December 2, 2010	December 2, 2017
Series X	US$84 million	4.88%	December 2, 2010 and January 4, 2011	December 2, 2020
Series Y	US$18 million	4.98%	December 2, 2010	December 2, 2022
Series Z	US$50 million	5.23%	December 2, 2010 and January 4, 2011	December 2, 2025
Series AA	Cdn$10 million	4.44%	December 2, 2010	December 2, 2015
Series BB	Cdn$50 million	5.38%	December 2, 2010	December 2, 2020
Series CC	US$25 million	3.64%	November 30, 2011	November 30, 2016
Series DD	US$12 million	4.23%	November 30, 2011	November 30, 2018
Series EE	US$68 million	4.79%	November 30, 2011	November 30, 2021
Series FF	Cdn$30 million	4.63%	November 30, 2011	November 30, 2018

Notes:

(1) Penn West has entered into contracts to fix the interest rate of the Series I Senior Notes at 6.95% in Canadian dollars and to fix the exchange rate on repayment.

(2) Penn West is obligated to repay US$5 million of the total US$30 million principal amount of the Series M notes outstanding on May 5 of each year ending in 2019.

(3) Penn West has entered into contracts to fix the interest rate of the Series N Senior Notes at 9.15% and to fix the exchange rate on repayment.

(4) Penn West has entered into contracts to fix the interest rate of the Series O Senior Notes at 9.22% and to fix the exchange rate on repayment.

Credit Facility

Penn West has an unsecured, revolving credit facility with a four-year term ending June 30, 2016 with a syndicate of Canadian and international banks. The credit facility has an aggregate borrowing limit of $3.0 billion. As at March 6, 2014, approximately $0.4 billion had been borrowed under the credit facility.

Additional Information

For additional information regarding our Senior Notes and our credit facility, see Notes 10 and 19 (collectively, the "**Financial Statement Disclosure**") to our restated audited consolidated financial statements for the year ended December 31, 2013, and "Financing" and "Liquidity and Capital Resources" (collectively, the "**MD&A Disclosure**") in our related restated management's discussion and analysis, both of which are available on SEDAR at www.sedar.com. The Financial Statement Disclosure and the MD&A Disclosure and are both incorporated by reference into this Annual Information Form.

DIRECTORS AND EXECUTIVE OFFICERS OF PENN WEST

The following table sets forth, as at March 6, 2014, the name, province and country of residence and positions and offices held for each of the directors and executive officers of Penn West, together with their principal occupations during the last five years. The directors of Penn West will hold office until the next annual meeting of Shareholders or until their respective successors have been duly elected or appointed.

Name, Province and Country of Residence	Positions and Offices Held with Penn West	Principal Occupations during the Five Preceding Years
James E. Allard(2)(5) Alberta, Canada	Director since June 30, 2006	Independent director and business advisor.
George H. Brookman(2)(4) Alberta, Canada	Director since August 3, 2005	Chief Executive Officer of West Canadian Industries Group Inc. (a digital printing and document management company).
Gillian H. Denham(1)(2)(4) Ontario, Canada	Director since June 13, 2012	Corporate director.
Richard L. George Alberta, Canada	Chairman of the Board and director since May 3, 2013	Partner of Novo Investment Group Ltd. (a Calgary-based investment management company). Chief Executive Officer of Suncor Energy Inc. ("**Suncor**") (an integrated energy company) prior to May 2012 and President and Chief Executive Officer of Suncor prior to December 2011.
Daryl H. Gilbert(3)(4)(5) Alberta, Canada	Director since January 11, 2008	Independent businessman since 2005.
Frank Potter(1)(4) Ontario, Canada	Director since June 30, 2006	Independent director for a number of public, private and not-for-profit corporations.
David E. Roberts Alberta, Canada	Director since June 19, 2013 President and Chief Executive Officer	President and Chief Executive Officer of Penn West since June 2013. Prior thereto, Executive Vice-President and Chief Operating Officer of Marathon Oil Corporation ("**Marathon**") (an independent energy company) from July 2011 to December 2012. Executive Vice-President Upstream of Marathon from April 2008 to July 2011. Prior thereto, Senior Vice-President Business Development of Marathon.

Name, Province and Country of Residence	Positions and Offices Held with Penn West	Principal Occupations during the Five Preceding Years
Jack Schanck(2)(3)(5) Alberta, Canada	Director since June 2, 2008	Independent director and businessman since June 2013. Prior thereto, President, Chief Executive Officer and director of Sonde Resources Corp., a public oil and natural gas company, since December 2010. Prior thereto, an independent businessman from January 2010 to December 2010. Prior thereto, Managing Partner of Tecton Energy, LLC, a private oil and natural gas company.
James C. Smith(1)(3) Alberta, Canada	Director since May 31, 2005	Independent director and consultant to a number of public and private oil and gas companies.
Jay W. Thornton(1)(3) Alberta, Canada	Director since June 5, 2013	Partner of Novo Investment Group Ltd. (a Calgary-based investment management company). Prior thereto, various operating and corporate executive positions with Suncor.
Mark P. Fitzgerald Alberta, Canada	Senior Vice President, Development	Senior Vice President, Development of Penn West since August 2011. Prior thereto, Senior Vice President, Production of Penn West from November 2008 to July 2011.
Gregg Gegunde Alberta, Canada	Senior Vice President, Production	Senior Vice President, Production of Penn West since February 2012. Prior thereto, Vice President, Production of Penn West from July 2011 to February 2012. Prior thereto, various Vice President roles in the development area and production engineering with Penn West.
S. Keith Luft Alberta, Canada	General Counsel and Senior Vice President, Corporate Services	General Counsel and Senior Vice-President, Corporate Services of Penn West since July 2013. Prior thereto, General Counsel and Senior Vice President, Stakeholder Relations of Penn West.
Todd H. Takeyasu Alberta, Canada	Executive Vice President and Chief Financial Officer	Executive Vice President and Chief Financial Officer of Penn West.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Human Resources and Compensation Committee.
(3) Member of the Reserves and Acquisitions and Divestitures Committee.
(4) Member of the Governance Committee.
(5) Member of the Health, Safety, Environment and Regulatory Committee.

As at March 6, 2014, the directors and executive officers of Penn West, as a group, beneficially owned, or controlled or directed, directly or indirectly, approximately one million Common Shares, or less than one percent of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the knowledge of Penn West, except as otherwise set forth herein, no director or executive officer of Penn West (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, Chief Executive Officer or Chief Financial Officer of any company (including Penn West), that:

(a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, Chief Executive Officer or Chief Financial Officer; or

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

To the knowledge of Penn West, except as otherwise disclosed herein, no director or executive officer of Penn West or shareholder holding a sufficient number of securities of Penn West to affect materially the control of Penn West (nor any personal holding company of any of such persons):

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

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

Daryl Gilbert was a director of Globel Direct, Inc. The company sought and received protection under the Companies' Creditors Arrangement Act (Canada) in June 2007, and after a failed restructuring effort a receiver was appointed by one of the company's lenders in December 2007. Cease trade orders dated September 24, 2008 and September 30, 2008 were issued by the Alberta Securities Commission and the British Columbia Securities Commission, respectively, for failure to file financial statements. The cease trade orders were issued following the appointment of the receiver and, as at the date hereof, have not been revoked. The company has since ceased operations and is delisted.

To the knowledge of Penn West, no director or executive officer of Penn West or shareholder holding a sufficient number of securities of Penn West to affect materially the control of Penn West (nor any personal holding company of any of such persons), has been subject to:

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

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

provided that for the purposes of the foregoing, a late filing fee, such as a filing fee that applies to the late filing of an insider report, is not considered to be a "penalty or sanction".

Conflicts of Interest

The Board of Directors has adopted a Code of Business Conduct and Ethics (the "**Code**") and a Code of Ethics for Directors, Officers and Senior Financial Management (the "**Oversight Code**" and together with the Code, the "**Codes**"). In general, the private investment activities of employees, directors and officers are not prohibited; however, should an existing investment pose a potential conflict of interest, the potential conflict is required by the Code to be disclosed to an officer or a member of Penn West's legal department and by the Oversight Code to be disclosed to the Board of Directors. Any other activities posing a potential conflict of interest are also required by the Codes to be disclosed to an officer or to a member of Penn

West's legal department. Any such potential conflicts of interests will be dealt with openly with full disclosure of the nature and extent of the potential conflicts of interests with Penn West.

It is acknowledged in the Codes that the directors may be directors or officers of other entities engaged in the oil and gas business, and that such entities may compete directly or indirectly with Penn West. Passive investments in public or private entities of less than one per cent of the outstanding shares will not be viewed as "competing" with Penn West. No executive officer or employee of Penn West should be a director, employee, contractor, consultant or officer of any entity that is or may be in competition with Penn West unless expressly authorized by an executive officer or the Board of Directors. Any director of Penn West who is a director or officer of, or who is otherwise actively engaged in the management of, or who owns an investment of one per cent or more of the outstanding shares, in public or private entities shall disclose such holding to the Board of Directors. In the event that any circumstance should arise as a result of such positions or investments being held or otherwise which in the opinion of the Board of Directors constitutes a conflict of interest which reasonably affects such person's ability to act with a view to the best interests of Penn West, the Board of Directors will take such actions as are reasonably required to resolve such matters with a view to the best interests of Penn West. Such actions, without limitation, may include excluding such directors, officers or employees from certain information or activities of Penn West.

The ABCA provides that in the event that an officer or director is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction.

As of the date hereof, Penn West is not aware of any existing or potential material conflicts of interest between Penn West or a Subsidiary of Penn West and any director or officer of Penn West or of any Subsidiary of Penn West.

Promoters

No person or company has been, within the two most recently completed financial years or during the current financial year, a "promoter" (as defined in the *Securities Act* (Ontario)) of Penn West or of a Subsidiary of Penn West.

AUDIT COMMITTEE DISCLOSURES

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

Composition of the Audit Committee and Relevant Education and Experience

As of March 6, 2014, the members of the Audit Committee are James C. Smith (Chairman), Gillian H. Denham, Frank Potter and Jay W. Thornton, each of whom is independent and financially literate within the meaning of NI 52-110. The following comprises a brief summary of each member's education and experience that is relevant to the performance of his or her responsibilities as an Audit Committee member.

James C. Smith (Chairman)

Mr. Smith is a Chartered Accountant with over 40 years of experience in public accounting and industry. Since 1998, he has been a business consultant and independent director to a number of public and private companies operating in the oil and natural gas industry. From February 2002 to June 2006, he served as the Vice-President and Chief Financial Officer of Mercury Energy Corporation, a private oil and natural gas company. Mr. Smith also held the position of Chief Financial Officer of Segue Energy Corporation, a private oil and natural gas company, from January 2001 to August 2003. From 1999 to 2000, Mr. Smith was the Vice-President and Chief Financial Officer of Probe Exploration Inc., a publicly traded oil and natural gas company. Mr. Smith served as the Vice-President and Chief Financial Officer of Crestar Energy Inc. from its inception in 1992 until 1998, during which time the company completed an initial public offering, was listed on the TSX and completed several major debt and equity financing transactions.

Gillian H. Denham

Ms. Denham, a Corporate Director, sits on the board of Morneau Shepell Inc., a provider of human resource consulting and outsourcing services, and the board of National Bank of Canada. From 2001 to 2005, she was Vice Chair, Retail Markets at Canadian Imperial Bank of Commerce ("**CIBC**"). Ms. Denham joined Wood Gundy in 1983, subsequently acquired by CIBC, as an Assistant Vice-President in Corporate Finance. Throughout her career at CIBC, she held progressively more senior roles. From 2006 to 2010, she was a member of the board of directors and Chair of the Human Resources and Compensation Committee of the Ontario Teachers' Pension Plan. Ms. Denham is a member of the board of governors and the audit committee of Upper Canada College. She holds an Honours Business Administration from University of Western Ontario School of Business and an MBA from Harvard Business School.

Frank Potter

Mr. Potter has a background in international banking in Europe, the Middle East and the United States. He managed the international business of one of Canada's principal banks before being appointed to the executive board of the World Bank in Washington where he served for nine years, including as lead director and Chairman of the bank's Steering Committee. Mr. Potter subsequently served as a Senior Advisor at the Department of Finance for the Canadian government. He is formerly the Chairman of Emerging Markets Advisors, Inc., a Toronto based consultancy that assists corporations in making and managing direct investments internationally. Mr. Potter serves on a number of boards, including Canadian Tire Corporation and the Royal Ontario Museum, where he is a former Chairman of the board of governors. Mr. Potter has experience serving on audit committees for several public issuers.

Jay W. Thornton

Mr. Thornton is a partner of Novo Investment Group Ltd., a Calgary-based investment management company. Mr. Thornton has over 27 years of oil and gas experience. He spent the first part of his career in various management positions with Shell. From 2000 to 2012, he held various operating and corporate executive positions with Suncor. He spent four years in Fort McMurray at Suncor's oil sands mining operations. His most recent position with Suncor was Executive Vice-President of Supply, Trading and Development. He has held previous board positions with both the Canadian Association of Petroleum Producers (CAAP) and the Canadian Petroleum Products Institute (CPPI). He was a past board member of the YMCA Fort McMurray and is currently a member of the board of North American Energy Partners Inc., US-based mining company Xinergy Ltd. and a private Calgary-based oil and gas company. Mr. Thornton is a graduate of McMaster University with an Honours degree in Economics. He is also a graduate of the Institute of Corporate Directors' (ICD) Directors Education Program.

Pre-Approval Policies and Procedures for Audit and Non-Audit Services

The terms of the engagement of Penn West's external auditors to provide audit services, including the budgeted fees for such audit services and the representations and disclaimer relating thereto, must be pre-approved by the entire Audit Committee.

With respect to any engagements of Penn West's external auditors for non-audit services, Penn West must obtain the approval of the Audit Committee or the Chairman of the Audit Committee prior to retaining the external auditors to complete such engagement. If such pre-approval is provided by the Chairman of the Audit Committee, the Chairman must report to the Audit Committee on any non-audit service engagement pre-approved by him at the Audit Committee's first scheduled meeting following such pre-approval.

If, after using its reasonable best efforts, Penn West is unable to contact the Chairman of the Audit Committee on a timely basis to obtain the pre-approval contemplated by the preceding paragraph, Penn West may obtain the required pre-approval from any other member of the Audit Committee, provided that any such Audit Committee member shall report to the Audit Committee on any non-audit service engagement pre-approved by him or her at the Audit Committee's first scheduled meeting following such pre-approval.

External Auditor Service Fees

The following table summarizes the fees billed to Penn West by KPMG LLP for external audit and other services during the periods indicated

Year	Audit Fees(1) ($)	Audit-Related Fees(2) ($)	Tax Fees(3) ($)	All Other Fees ($)
2013	1,340,000	145,700	-	-
2012	1,120,000	146,000	38,000	-

Notes:

(1) The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services, including fees for the integrated audit of Penn West's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements, reviews in connection with acquisitions and Sarbanes-Oxley Act related services, long-form comfort letters related to the public offering of securities and review procedures on the unaudited interim consolidated financial statements.

(2) The aggregate fees billed in each of the last two fiscal years by our external auditor for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements (and not included in audit services fees in note (1)). The services comprising the fees disclosed under this category principally consisted of Penn West's portion of fees for the Peace River Oil Partnership audit and French translation services.

(3) The aggregate fees billed in each of the last two fiscal years by our external auditor for professional services for tax compliance, tax advice and tax planning. The services comprising the fees disclosed under this category principally relate to general tax compliance and planning services.

Reliance on Exemptions

At no time since the commencement of Penn West's most recently completed financial year has Penn West relied on any of the exemptions contained in Sections 2.4, 3.2, 3.4 or 3.5 of NI 52-110, or an exemption from NI 52-110, in whole or in part, granted under Part 8 thereof. In addition, at no time since the commencement of Penn West's most recently completed financial year has Penn West relied upon the exemptions in Subsection 3.3(2) or Section 3.6 of NI 52-110. Furthermore, at no time since the commencement of Penn West's most recently completed financial year has Penn West relied upon Section 3.8 of NI 52-110.

Audit Committee Oversight

At no time since the commencement of Penn West's 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.

DIVIDENDS AND DIVIDEND POLICY

Dividend Policy

The Board of Directors has adopted a quarterly dividend policy with a current dividend amount of Cdn$0.14 per Common Share. The quarterly dividend is paid on or about the 15th day of the month following the end of each quarter to Shareholders of record at the end of such quarter.

Notwithstanding the foregoing, the amount of future cash dividends, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, compliance with any restrictions on the declaration and payment of dividends contained in any agreement to which Penn West is a party from time to time (including, without limitation, the agreements governing Penn West's credit facilities and Senior Notes), and the satisfaction of liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board intends to review Penn West's dividend policy on a quarterly basis. **Depending on the foregoing factors and any other factors that the Board deems relevant from time to time, many of which are beyond the control of our Board and management team, the Board may change our dividend policy following any such quarterly review or at any other time that the Board deems appropriate, and as a result, future cash dividends could be reduced or suspended entirely. The market value of our Common Shares may deteriorate if we reduce or suspend the amount of cash dividends that we pay in the future and such deterioration may be material.** See "Risk Factors". As at the date hereof, the Board does not have any intention to change Penn West's dividend policy.

Effective from January 1, 2011, all dividends paid on our Common Shares to shareholders residing in Canada have been and will continue to be designated as "eligible dividends" for Canadian income tax purposes. This designation will apply until we notify Shareholders otherwise. Shareholders seeking further information regarding the taxation of "eligible dividends" should contact their Canadian tax advisor.

The credit agreement governing our syndicated credit facility and each of the note purchase agreements governing our Senior Notes contain provisions which restrict our ability to pay dividends to Shareholders in the event of the occurrence of certain events of default. The full text of the agreements governing our credit facility and our Senior Notes is available on SEDAR at www.sedar.com. For additional information regarding our credit facility and our Senior Notes, see "Capitalization of Penn West – Debt Capital".

Dividend Reinvestment and Optional Common Share Purchase Plan

Our Dividend Reinvestment and Optional Common Share Purchase Plan (the "**DRIP**") provides eligible Shareholders with the advantage of acquiring additional Common Shares by reinvesting their dividends. At our discretion, Common Shares will be acquired with dividends either on the TSX at prevailing market rates or from treasury at 95% of the "average market price" (as defined in the DRIP). Generally, we expect to issue Common Shares from treasury at a discount to satisfy the dividend reinvestment component of the DRIP.

Eligible Shareholders may also make optional cash payments of a minimum of $500 up to a maximum of $15,000 per quarter to purchase additional Common Shares. Common Shares purchased with optional cash payments will be acquired either on the TSX at prevailing market rates or from treasury at the average market price (without a discount).

We will determine prior to each dividend payment date the number of Common Shares, if any, that will be made available from treasury under the DRIP on such payment date. No assurances can be made that Common Shares will be made available from treasury on a regular basis, or at all.

Shareholders who are residents of Canada are eligible to participate in the dividend reinvestment component of the DRIP and to purchase new Common Shares with optional cash payments. Shareholders who are resident in the United States are eligible to participate in the dividend reinvestment component of the DRIP. United States residents are not eligible to make optional cash payments to purchase additional Common Shares pursuant to the DRIP. With the exception of the foregoing, unless otherwise announced by us, Shareholders who are not residents of Canada are not entitled to participate, directly or indirectly, in the DRIP.

Dividends Declared Payable to Shareholders of Penn West

During the financial years ended December 31, 2011, 2012 and 2013, Penn West declared payable the following amount of cash dividends per Common Share:

Quarter	**2013 Dividends Declared Payable ($)**	**2012 Dividends Declared Payable ($)**	**2011 Dividends Declared Payable ($)**
First Quarter	0.27	0.27	0.27
Second Quarter	0.27	0.27	0.27
Third Quarter	0.14	0.27	0.27
Fourth Quarter	0.14	0.27	0.27
Total	0.82	1.08	1.08

MARKET FOR SECURITIES

Trading Price and Volume

The following tables set forth certain trading information for the Common Shares in 2013 as reported by the TSX and the NYSE.

	TSX		
Period	Common Share price ($) High	Common Share price ($) Low	Volume
January	11.15	9.96	23,758,401
February	10.81	9.81	30,241,337
March	12.06	9.82	26,313,849
April	11.17	8.82	36,208,263
May	10.80	9.08	39,297,964
June	12.05	10.28	42,384,432
July	13.57	10.62	37,243,603
August	12.77	11.58	17,568,213
September	12.22	11.28	16,515,009
October	12.10	11.09	21,407,559
November	11.65	8.42	34,179,307
December	9.54	8.78	22,264,559

	NYSE		
Period	Common Share price ($US) High	Common Share price ($US) Low	Volume
January	11.33	10.10	37,618,463
February	10.83	9.53	38,288,313
March	11.77	9.55	42,413,604
April	11.01	8.59	76,800,095
May	10.44	9.00	67,556,447
June	11.80	9.98	67,061,064
July	13.16	10.03	60,513,347
August	12.43	11.16	33,490,937
September	11.85	10.95	24,939,631
October	11.75	10.65	35,065,620
November	11.17	8.02	71,171,849
December	8.99	8.28	48,691,975

Prior Sales

Other than incentive securities issued pursuant to Penn West's director and employee compensation plans and the Senior Notes, Penn West does not have any classes of securities that are outstanding but that are not listed or quoted on a market place.

Escrowed Securities and Securities Subject to Contractual Restriction on Transfer

To Penn West's knowledge, no securities of Penn West are held in escrow, are subject to a pooling agreement, or are subject to a contractual restriction on transfer (except in respect of pledges made to lenders and except in respect of incentive securities issued pursuant to Penn West's director and employee compensation plans).

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, upgrading, transportation and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through policy enacted by the governments of Canada, Alberta, British Columbia, Saskatchewan and Manitoba, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). 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 licence from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following, an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price realized for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production and oil sands projects. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally, the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula that is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40 percent.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula, with the maximum royalty payable under the royalty regime set at 36 percent.

Oil sands projects are also subject to Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1 and 9 percent depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are 1 percent when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9 percent when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1 to 9 percent and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25 percent and increase for every dollar of market price of oil increase above $55 up to 40 percent when oil is priced at $120 or higher. In addition, concurrent with the implementation of the New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is four percent of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques, and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5 percent for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5 percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5 percent for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5 percent with volume and production month limits set according to the depth (including the horizontal distance) of the well, retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice if it decides to discontinue the program.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**EOR**") scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20 percent of the sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25 percent.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs, including the following:

- *Deep Royalty Credit Program* providing a royalty credit defined in terms of a dollar amount applied against royalties, which is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres (or 1,900 metres if spud after August 1, 2009) and if certain other criteria are met. The British Columbia government implemented a 3% minimum royalty rate effective April 1, 2013;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date subsequent to December 1, 2003, or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m^3;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m^3 per metre of depth for exploratory wildcat wells and less than 11 m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 m^3; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program which provides royalty credits for up to 50 percent of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3 percent minimum royalty on affected wells with deep well/deep re-entry credits. The 3 percent minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month.

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002, and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for old oil, new oil and third tier oil, and 250 m^3 per month for fourth tier oil. Where average wellhead prices are below the established base prices of \$100 per m^3 for third and fourth tier oil and \$50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5 percent for all fourth tier oil, 10 percent for heavy oil that is third tier oil or new oil, 12.5 percent for southwest designated oil that is third tier oil or new oil, 15 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20 percent for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30 percent for all fourth tier oil, 25 percent for heavy oil that is third tier oil or new oil, 35 percent for southwest designated oil that is third tier oil or new oil, 35 percent for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45 percent for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government (effective February 1, 2012), the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least

3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations, 2012* which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3 per month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5 percent for all fourth tier gas, 15 percent for third tier or new gas, and 20 percent for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30 percent for all fourth tier gas, 35 percent for third tier and new gas, and 45 percent for old gas. The current regulatory scheme provides for certain differences with respect to the administration of fourth tier gas which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5 percent) and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5 percent) and freehold tax rates (a freehold production tax rate of 0 percent) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1 percent of gross revenues on EOR projects pre-payout and 20 percent of EOR operating income post-payout and a freehold production tax of 0 percent pre-payout and 8 percent post-payout on operating income from EOR projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5 percent for oil produced prior to April 2013 and 2.25 percent for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting from the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards commenced on July 1, 2012 for new wells and facilities licensed on or after such date. The new standards will apply to existing licensed wells and facilities on July 1, 2015.

Manitoba

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas and NGL production from Crown lands are equal to 12.5 percent of the volume of natural gas sold, calculated for each production month.

Producers of oil, natural gas and NGL from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2 percent of the volume sold, calculated for each production month. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the "**Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Holiday oil volumes must be produced within 10 years of the finished drilling date or the completion date of a major workover. Wells drilled or receiving a marginal well major workover incentive after December 31, 2013 and prior to January 1, 2019 must pay a minimum royalty on Crown production or a minimum tax on freehold production. Wells drilled for injection, or converted to injection wells, in an approved enhanced recovery project, earn a one year holiday for portions of the project area.

The Program consists of the following components, such components being subject to additional considerations under the

Crown Royalty and Incentives Regulation:

- *Vertical Well Incentive* provides licensees of a vertical development or exploratory well drilled after December 31, 2013 and prior to January 1, 2019 with a holiday oil volume (a "**HOV**") of 500 m^3. To qualify, the well must be less than 1.6 kilometres from the nearest well cased for production from the same or deeper zone;

- *Exploration and Deep Well Incentive* provides a HOV for exploratory or deep oil development wells drilled after December 31, 2013 and prior to January 1, 2019 as follows:

  - Non-deep exploratory wells drilled more than 1.6 kilometres from the nearest well cased for production from the same or deeper zone earn a HOV of 4,000 m^3;

  - Deep exploratory wells drilled below the Birdbear formation earn a HOV of 8,000 m^3; and

  - Deep development wells completed for production in the Birdbear formation or deeper earn a HOV of 8,000 m^3;

- *Horizontal Well Incentive* provides a HOV of 8,000 m^3 for any horizontal well drilled after December 31, 2013 and prior to January 1, 2019 achieving an angle of at least 80 degrees for a minimum distance of 100 metres;

- *Marginal Well Major Workover Incentive* provides a HOV of 500 m^3 for any marginal well where a major workover is completed prior to January 1, 2019. A marginal oil well is a well or abandoned well that was not operated over the previous 12 months or that produced at an average rate of less than 3 m^3 per operating day;

- *Pressure Maintenance Project Incentive* provides a one-year exemption from the payment of Crown royalties or freehold production taxes for a unit tract in which an injection well is drilled or a well is converted to water injection. For a well that is converted to injection after December 31, 2013 and before January 21, 2019 and that has a remaining HOV, the exemption will be extended to 18 months; and

- *Solution Gas Conservation Incentive* provides a royalty and tax exemption on gas until December 31, 2018 for projects that capture solution gas implemented after December 31, 2013.

The Holiday Oil Volume Account, which allowed the movement of HOV to and from wells under specific conditions, will be eliminated as of January 1, 2015. Until December 31, 2014, the holder of an existing account may make a one-time transfer of 2,000 m^3 to a well drilled between January 1 and December 31, 2014.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80 percent of the crude oil and natural gas rights in the southwestern portion of the province. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. In 2013, Alberta Energy placed an indefinite hold on serving shallow rights reversion notices for leases and licences that were granted prior to January 1, 2009. Alberta Energy stated that it will provide the industry with notice if, in the future, a decision is made to serve shallow rights reversion notices.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emitting of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements for the satisfactory abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Federal

Pursuant to the Prosperity Act, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* the ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 30, 2014, the AER is expected to assume the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "**ALSA**") provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land, and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 percent of the province's oilsands resources and much of the Cold Lake oilsands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres and includes 45 percent of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force on April 1, 2014.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**BCO&G Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the BCO&G Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act* requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers, and procedural aspects, including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Manitoba

In Manitoba, the Petroleum Branch of Innovation, Energy and Mines develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of crude oil and natural gas resources. Oil and gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* (the "**MBOGA**") and *The Oil and Gas Production Tax Act,* and related regulations and guidelines.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

On May 1, 2013, the AER began to implement a three year program of changes to the LLR Program. Some of the important changes which will be implemented through this three year process include:

- a 25 percent increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years results in the average being more sensitive to price changes); and

- a change to the present value and salvage factor, which increase to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

The changes will be implemented over a three-year period, ending May 2015. The current changes have already had an effect on oil and gas producers in Alberta as the May 1, 2013 changes resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security with the AER. The changes to the AB LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

British Columbia

In British Columbia, the BCO&G Commission implements the Liability Management Rating ("**LMR**") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the BCO&G Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**"). The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Manitoba

To date, Manitoba has not implemented a liability management rating program similar to those found in the other western provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the *Drilling and Production Regulations*. In certain circumstances, a performance deposit may be refunded. The MBOGA also establishes the Abandonment Fund Reserve Account (the "**Abandonment Fund**"). The Abandonment Fund is a source of funds that may be used to operate or abandon a well when the licensee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility. Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred as well as annual levies for inactive wells and batteries.

Climate Change Regulation

Federal

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17 percent reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31 percent larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach and aims for a 50 percent reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "**Established Facilities**" and "**New Facilities**". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12 percent of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000 or in a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2 percent from their baseline in the fourth year of commercial operation, 4 percent of their baseline in the fifth year, 6 percent of their baseline in the sixth year, 8 percent of their baseline in the seventh year and 10 percent of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

We do not operate any facilities in Alberta that are covered by the CCEMA and the SGER. However, we do have minor working interests in non-operated facilities that are subject to the CCEMA and the SGER. As at the date hereof, we do not believe that our financial obligations associated with such non-operated facilities are material.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of CO_2 equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax. In 2013, the amount of carbon tax paid by us pursuant to this legislation with respect to our operated and non-operated properties in British Columbia was not material to us.

In the 2012 Budget, British Columbia announced that the government would undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review last year, British Columbia confirmed that: it will keep its revenue-neutral carbon tax; the current carbon tax rates and tax base will be maintained, and; revenues will continue to be returned through tax reductions.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33 percent reduction in the 2007 level of GHG emissions by 2020 and an 80 percent reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under development.

Penn West's linear facility in British Columbia is covered by the Cap and Trade Act. We anticipate that we will have two facilities over the 25,000 tonne threshold, one facility between the 10,000 and 25,000 tonnes threshold, and 16 facilities between the 1,000 and 10,000 tonnes threshold. In addition, we have working interests in several non-operated facilities that are subject to the Cap and Trade Act. As at the date hereof, we do not believe that our financial obligations associated with the reporting and verification requirements under the Cap and Trade Act are material.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced The Management and Reduction of Greenhouse Gases Act (the "MRGGA") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20 percent reduction in GHG emissions from 2006 levels by 2020. The MRGGA and related regulations have yet to be proclaimed in force.

Manitoba

The Government of Manitoba commenced public consultations with respect to the development of a cap and trade system to reduce GHG emissions in 2010. The enactment of The Climate Change and Emissions Reductions Act (Manitoba) set emission reduction targets as of December 31, 2012 at 6 percent below 1990 emissions and details the commitment of the Government of Manitoba to various initiatives in an effort to reduce GHG emissions. However, no legislation has been enacted which imposes mandatory emission reduction targets on emitters.

Penn West and the Environment

Penn West understands its responsibilities for reducing the environmental impacts from its operations and recognizes the interests of other land users in resource development areas, and conducts its operations accordingly. Penn West is committed to mitigating the environmental impact from its operations, and to involving stakeholders throughout the exploration, development, production and abandonment process. Penn West's environmental programs encompass resource conservation, stakeholder communication and site abandonment/reclamation. Its environmental programs are monitored to ensure they comply with all government environmental regulations and with Penn West's own environmental policies. The results of these programs are reviewed with Penn West's management and operations personnel.

Penn West maintains a program of detailed inspections, audits and field assessments to determine and quantify the environmental liabilities that will be incurred during the eventual decommissioning and reclamation of its field facilities. Penn West pursues a program of environmental impact reduction aimed at minimizing these future corporate liabilities without hampering field productivity. This program, launched in 1994, is ongoing, and includes measures to remediate potential contaminant sources, reclaim spill sites and abandon unproductive wells and shut-in facilities.

Alberta, British Columbia and Saskatchewan are currently the only jurisdictions in which Penn West operates that have passed legislation regarding GHG emissions, although several are contemplating new legislation. Penn West does not operate any facilities in Alberta that are regulated to reduce GHG emissions and has no facilities that are required to report their emissions. Penn West has minor working interests in several non-operated facilities that are required to meet the requirements of the Alberta GHG regulations. All of Penn West's fuel use in British Columbia is subject to a carbon tax based on consumption. Penn West is required to report its emissions in British Columbia and expects to have reduction requirements under a cap and trade system when implemented. Penn West's financial obligation, in both Alberta and British Columbia, related to compliance with legislation regarding GHG emissions is not material at this time.

Because the federal and provincial programs relating to the regulation of the emission of GHGs and other air pollutants continue to be developed, Penn West is currently unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that Penn West could face increases in costs in order to comply with emissions legislation.

However, in cooperation with the Canadian Association of Petroleum Producers, Penn West continues to work cooperatively with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance, and supports continued investment in the oil and gas sector.

Penn West provides additional information in respect of its GHG emissions in the annual international Carbon Disclosure Project, which provides detailed information regarding our emissions, business strategy, governance and potential risks.

Penn West is committed to meeting its responsibilities to protect the environment wherever it operates. Penn West anticipates that its expenditures, both capital and expense in nature, will continue to increase as a result of operational growth and increasing legislation relating to the protection of the environment. Penn West will be taking such steps as required to ensure continued compliance with applicable environmental legislation in each jurisdiction in which it operates. Penn West believes that it is currently in compliance with applicable environmental laws and regulations in all material respects. Penn West also believes that it is reasonably likely that the trend towards heightened and additional standards in environmental legislation and regulation will continue.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of Penn West. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form. Securityholders and potential securityholders should consider carefully the information contained herein and, in particular, the following risk factors. If any of these risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in dividends paid on, and the market price of, our Common Shares. The risks described below are not an exhaustive list of the risks that may affect our business, nor should they be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.

Volatility in oil and natural gas prices could have a material adverse effect on our results of operations and financial condition, which in turn could negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

Our results of operations and financial condition are dependent upon the prices that we receive for the oil and natural gas that we sell. Historically, the oil and natural gas markets have been volatile and are likely to continue to be volatile in the future. Oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to changes in supply, demand, market uncertainty and other factors that are beyond our control. These factors include, but are not limited to:

- the limitations on the ability of Western Canadian energy producers to export oil, natural gas and natural gas liquids to U.S. markets and world markets and the resulting discount that Western Canadian energy producers may receive for their products as compared to U.S. and international benchmark commodity prices;
- the availability of transportation infrastructure, and in particular:
    - our ability to acquire space on pipelines that deliver crude oil and natural gas to commercial markets or alternatively contract for the delivery of our products by rail;
    - deliverability uncertainties related to the distance of our production from existing pipeline, railway line, processing and storage facility infrastructure; and
    - operational problems affecting the pipelines, railway lines and facilities on which we rely;
- global energy policy, including the ability of OPEC to set and maintain production levels and influence prices for oil;
- existing and threatened political instability and hostilities;
- foreign supply of oil and natural gas, including liquefied natural gas;
- weather conditions;
- the overall level of energy demand;
- production and storage levels of natural gas;
- government regulations and taxes;
- currency exchange rates;
- the effect of worldwide environmental and/or energy conservation measures;

- the price and availability of alternative energy supplies;
- the overall economic environment; and
- the advent of new technologies.

Any decline in the price of oil or natural gas could have a material adverse effect on our operations, financial condition, borrowing ability, reserves and the level of expenditures for the development of reserves. Fluctuations in the price of oil and natural gas will also have an effect on the acquisition costs of any future oil and natural gas properties that we may acquire. In addition, cash dividends paid to our Shareholders are highly sensitive to the prevailing price of crude oil and natural gas and may decline with any decline in the price of oil or natural gas.

The price of oil and natural gas is affected by political events throughout the world. Any such event could result in a material decline in prices and in turn result in a reduction in the market price of our Common Shares and the amount of cash dividends paid to Shareholders.

Political events throughout the world that cause disruptions in the supply of oil continue to affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising in North Africa, the Middle East and other areas of the world have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of our revenue and consequently the market price of our Common Shares and the amount of cash dividends paid to Shareholders.

In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of a terrorist attack it could have a material adverse effect on us. We do not currently have insurance to protect against the risk of terrorism.

We cannot predict the impact of changing demand for oil and natural gas products.

Conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

The failure to successfully execute our long-term plan and/or achieve our related operational, financial and other performance targets and/or realize the anticipated benefits therefrom, could negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

In November 2013, we announced that our strategic alternatives review was complete and that our Board, based on recommendations from the Special Committee and our financial advisor, had determined that our long-term plan (the "**Plan**") to deleverage our balance sheet, continue operational and cost control improvements, and focus on light oil development integrated with waterflood programs concentrated in our Cardium, Slave Point and Viking plays, was the best current strategy to maximize Shareholder value. We announced that the objective of the Plan was, among other things, to provide Shareholders with compound annual per share growth in oil production and funds flow subsequent to a deleveraging period and provide Shareholders with a return through a sustainable dividend. In furtherance of the Plan, we announced our intention to sell $1.5 to $2.0 billion of non-core assets before 2015 in order to deleverage our balance sheet of which $486 million was closed during the fourth quarter of 2013 and $175 million is scheduled to close in mid-March 2014.

Our Plan and related operational, financial and other performance targets (the "**Performance Targets**") are used by our Board and senior management for strategic planning purposes. Our Plan and related Performance Targets are not, and should not be construed as, forecasts, budgets, or guidance and should not be relied upon as (and are not) assurances of future performance. Our Board has only approved capital budgets and production guidance for 2014. Budgets and guidance subsequent to 2014 have not been finalized and are subject to a variety of factors and contingencies, including our operational results and any adjustments that we may make to our Plan and/or the assumptions on which it is based.

Our Plan and related Performance Targets are based on various assumptions, including assumptions relating to the operational activities that we will undertake and the success thereof, the assets that we will sell, the prices that we will receive for our products, the exchange rates and interest rates to which we will be subject, the debt levels that we will carry, our production levels and product mix, our funds flow, the amount of cash taxes that we will pay, the amount of dividends that we will pay, the hedging activities that we will undertake, and the number of Common Shares that we will have outstanding. While we believe that our assumptions are reasonable, no assurance can be given that our assumptions will prove to be correct, and variances could be material.

As with any business, we expect that we will need to continually adjust our Plan to reflect internal and external factors, such as our operational results, and to reflect changes to the assumptions on which our Plan and related Performance Targets are based. When changes are made to our Plan and/or our assumptions, our related Performance Targets will also change. Any changes to our Plan and/or such Performance Targets may adversely affect the market price of our Common Shares and may result in a reduction in the amount of dividends that we pay to Shareholders.

If: (i) we are unable to successfully execute our Plan (whether because one or more of the assumptions underlying our Plan proves to be incorrect (including if we are unable to complete the non-core asset dispositions contemplated by our Plan on favourable terms or at all) or for other reasons) and/or (ii) we are not successful in achieving some or all of the Performance Targets contemplated by our Plan, and/or (iii) some or all of the benefits that we anticipate will accrue to us and our securityholders as a result of the successful execution of our Plan do not materialize; the market price of our Common Shares and/or the amount of cash dividends paid to our Shareholders may be adversely affected.

We may be unable to successfully compete with other companies in our industry, which could negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

There is strong competition relating to all aspects of the oil and gas industry. We compete with numerous other exploration and production companies for, among other things:

- resources, including capital and skilled personnel;
- the acquisition of properties with longer life reserves and exploitation and development opportunities; and
- access to equipment, markets, transportation capacity, drilling and service rigs and processing facilities.

If we are unable to acquire or develop additional reserves, the value of our Common Shares and the amount of cash dividends paid to Shareholders will decline.

Absent equity capital injections, increased debt levels or the efficient deployment of capital investments by us, our production levels and reserves will decline over time and, absent changes to other factors such as increases in commodity prices or improvements to our capital efficiency, the amount of cash dividends paid to our Shareholders will also decline over time.

Our future oil and natural gas reserves and production, and therefore our cash flow, will be highly dependent on our success in exploring and exploiting our reserves and land base and acquiring additional reserves. Without reserve additions through acquisition, exploration or development activities, our reserves and production will decline over time as our existing reserves are depleted.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. To the extent that we are required to use higher proportions of our cash flow to finance capital expenditures or property acquisitions, the amount of cash dividends paid to our Shareholders could be reduced.

There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

We may experience challenges adopting new technologies and our costs may increase as a result of such adoption.

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we do. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be materially adversely affected. If we are unable to utilize the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

We are participating in some large projects and have more concentrated risks in these areas of our operations.

We manage a variety of small and large projects in the conduct of our business. We have undertaken several large development projects, including our interests in the Peace River Oil Partnership and our joint venture with an affiliate of Mitsubishi Corporation. Project delays may impact expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- the availability of processing capacity;
- the availability and proximity of transportation infrastructure;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we could be unable to execute projects on time, on budget, or at all, and may not be able to effectively market the oil and natural gas that we produce.

Fluctuations in foreign currency exchange rates and interest rates could adversely affect our business, and adversely affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

World oil prices are denominated in United States dollars and the Canadian dollar price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which fluctuates over time. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect, among other things, our oil production revenues in Canadian dollars. We generally fund our cash costs, including our cash dividends, in Canadian dollars. Strengthening of the Canadian dollar (excluding risk management activities) against the United States dollar negatively affects the amount of Canadian dollar funds available to us for reinvestment and for the payment of future cash dividends, and negatively affects the future value of our reserves as calculated by independent evaluators.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a reduced amount available to fund our exploration and development activities and a decrease in the amount of cash dividends paid to Shareholders, both of which could negatively impact the market price of the Common Shares.

The incorrect assessment of value at the time of acquisitions could adversely affect the value of our Common Shares and the amount of cash dividends paid to our Shareholders.

Acquisitions of oil and gas properties or companies will be based in large part on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated. If actual reserves or production are less than we expect, our revenues and consequently the value of our Common Shares and the amount of cash dividends paid to Shareholders could be negatively affected.

Acquiring, exploring for, developing, and producing from oil and natural gas assets involves many risks. Losses resulting from the occurrence of one or more of these risks may adversely affect our business and thus the value of our Common Shares and the amount of cash dividends paid to our Shareholders.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Penn West depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and on our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of Penn West may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that we will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Acquiring, exploring for, developing, and producing from oil and natural gas assets involves many risks. These risks include, but are not limited to:

- encountering unexpected formations or pressures;
- premature declines of reservoirs;
- the invasion of water into producing formations;
- blowouts, explosions, equipment failures and other accidents;
- sour gas releases;
- uncontrollable flows of oil, natural gas or well fluids;
- personal injury to staff and others;
- adverse weather conditions, such as wild fires and flooding; and
- pollution and other environmental risks, such as fires and spills.

These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects.

Although we maintain insurance in accordance with customary industry practice based on our projected cost benefit analysis of maintaining such insurance, we are not fully insured against all of these risks, not all risks are insurable, and liabilities associated with certain risks could exceed policy limits or not be covered. Like other oil and natural gas companies, we attempt to conduct our business and financial affairs so as to protect against political and economic risks applicable to operations in the jurisdictions where we operate, but there can be no assurance that we will be successful in so protecting our assets.

Seasonal factors and unexpected weather patterns (including wild fires and flooding) may lead to declines in our activities and thereby adversely affect our business, the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and 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.

Our operations are susceptible to the impacts of wild fires and flooding. In recent years, our production levels (and as a result our revenues) have at times been materially and adversely affected by wild fires and flooding. In addition to the loss of revenue that results from the loss of production, when our operations are affected by wild fires and/or flooding, we incur expenses responding to such events, repairing damaged equipment, and resuming operations. Although our insurance policies may compensate us for part of our losses, they will not compensate us for all of our losses. In addition, wild fires and/or flooding consume both financial resources and management and employee time that would otherwise be directed towards the development of our business and the pursuit of our business strategy. We can offer no assurance that the severe wild fires and flooding that have at times plagued our operations in recent years will not occur again in the future with equal or greater severity.

Seasonal factors and unexpected weather patterns, including wild fires and flooding, may lead to material declines in our exploration, development and production activities and may consume material amounts of our financial and human resources, and thereby materially and adversely affect our results of operations and financial condition.

We use conventional recovery methods, such as horizontal multi-stage fracturing technology, and non-conventional recovery methods, such as enhanced oil recovery technologies, both of which are subject to significant risk factors which could lead to the delay or cancellation of some or all of our projects, which could adversely affect the market price of our Common Shares and our dividends to Shareholders.

Penn West utilizes new drilling and completion technologies, including horizontal multi-stage fracture completions, intended to increase the resource recovery from known oil and natural gas fields. However, Penn West may not realize the anticipated increase in resource recovery from the employment of such techniques due to particular reservoir characteristics or other adverse factors.

Hydraulic fracturing typically involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (natural gas and oil) production. Hydraulic fracturing is being used to produce commercial quantities of natural gas and oil from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delay or increased operating costs or third party or governmental claims, and could increase our cost of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

The potential or planned use of enhanced oil recovery ("**EOR**") methods such as steam injection (steam assisted gravity drainage, cyclical steam stimulation and steam flooding), water injection, solvent injection and firefloods to increase the ultimate recovery of oil resources in place are subject to significant risk factors. These factors include but are not limited to the following:

- changing economic conditions (including commodity pricing and operating and capital expenditure fluctuations);
- changing engineering and technical conditions (including the ability to apply EOR methods to the reservoir and the production response thereto);

- large development programs may need to be spread over a longer time period than initially planned due to the requirement to allocate capital expenditures to different periods;
- surface access and deliverability issues (including landowner and stakeholder relations, weather, pipeline, road and processing matters);
- environmental regulations relating to such items as GHG emissions and access to water, which could impact capital and operating costs; and
- the availability of sufficient financing on acceptable terms.

The use or potential or planned use of CO_2 miscible flooding to increase the oil recovery from large legacy oil pools is subject to significant risk factors which could lead to the delay or cancellation of some or all of these projects. These factors include, but are not limited to:

- the existence of commercial scale CO_2 supply and infrastructure (including the ability to capture and transport the miscible agent to us at an economic cost);
- changing economic conditions (including commodity pricing and operating and capital expenditure fluctuations);
- changing engineering and technical conditions (including the ability to apply CO_2 EOR methods to the reservoir and the production response thereto);
- large development programs may need to be spread over a longer time period than planned due to capital allocation requirements;
- the need to obtain required approvals from regulatory authorities from time to time;
- surface access and deliverability issues (including weather, pipeline, road and processing matters);
- the availability of sufficient financing on acceptable terms;
- changing regulatory frameworks, which could impact our long-term storage liability and our monitoring, measurement and verification costs on CO_2 miscible flood projects;
- changing royalty structures which may impact CO_2 flood economics; and
- the potential for out-of-zone and wellbore leakage which could delay or cause the cancellation of some or all of these projects.

Dividends might be reduced during periods in which we make capital expenditures using our cash flow from operations, which could negatively affect the market price of our Common Shares.

Future oil and natural gas reserves and hence revenues are dependent on our success in exploiting existing properties and acquiring additional reserves. We currently intend to dividend a portion of our net cash flow to Shareholders rather than reinvesting it in reserve additions and production growth or maintenance. Accordingly, if external sources of capital, including the issuance of additional Common Shares, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves could be impaired. To the extent that we are required to use our cash flow from operations to finance capital expenditures or property acquisitions or to repay indebtedness, the amount of cash available for the payment of dividends to Shareholders will be reduced. Additionally, we cannot guarantee that we will be successful in exploring for and developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserve additions, our reserves will decline over time and as a consequence, either production from, or the average reserve life of, our properties will decline. Either decline may result in a reduction in the value of our Common Shares and in a reduction in the amount of cash available for the payment of dividends to Shareholders.

Our hedging program could result in us not realizing the full benefit of oil and natural gas price increases.

We manage the risk associated with changes in commodity prices by entering into oil and natural gas price hedges. When we hedge our commodity price exposure, we could forego the benefits we would otherwise experience if commodity prices increase. In addition, commodity hedging activities could expose us to cash and income losses including royalty burdens that are disproportionate to our realized pricing. To the extent that we engage in risk management activities, there are potential credit risks associated with counterparties with which we contract.

We may not be able to achieve the anticipated benefits of acquisitions and the integration of acquisitions may result in the loss of key employees and the disruption of on-going business relationships.

We make acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner, as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters, and may also result in the loss of key employees, the disruption of on-going business, supplier, customer and employee relationships and deficiencies in internal controls or information technology controls. We continually assess the value and mix of our assets in light of our business plans and strategic objectives. In this regard, non-core assets are periodically disposed of so that we can focus our efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could be expected to realize less than their carrying value in our financial statements.

Actual reserves will vary from reserves estimates and those variations could be material and negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquid reserves and resources and cash flow to be derived therefrom, including many factors beyond our control. The reserve and associated revenue information set forth herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and resources and the future net revenue therefrom are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- estimated production decline rates;
- estimated ultimate recovery of reserves;
- changes in technology;
- timing and amount and effectiveness of future capital expenditures;
- marketability and price of oil and natural gas;
- royalty rates;
- the assumed effects of regulation by governmental agencies; and
- future operating costs;

all of which may vary from actual results. As a result, estimates of the economically recoverable oil and natural gas reserves or estimates of resources attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Our actual production, revenues and development and operating expenditures will vary from reserve and resource estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are sometimes based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, Sproule has used forecast price and cost estimates in calculating reserve quantities included herein. Actual future net revenue will be affected by other factors including but not limited to actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and revenue derived from reserves will vary from the reserve estimates contained in the Engineering Report summarized herein, and such variations could be material. The Engineering Report summarized herein is based in part on the assumption that certain activities will be undertaken by us in future years and the further assumption that such activities will be successful. The reserves and estimated revenue to be derived therefrom contained in the Engineering Report summarized herein will be reduced in future years to the extent that such activities are not undertaken or, if undertaken, do not achieve the level of success assumed in the Engineering Report summarized herein. The reserves evaluation described herein is effective as of a specific date and, except as otherwise noted, has not been updated and thus does not reflect changes in our reserves since that date.

We may not be able to repay all or part of our indebtedness, or alternatively, refinance all or part of our indebtedness on commercially reasonable terms. We may not be able to comply with the covenants (and in particular the financial covenants) contained in our debt instruments. The occurrence of any one of these events could have a material adverse effect on our results of operations and financial condition, which in turn could negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

We currently have a credit facility in place that has an aggregate borrowing limit of $3.0 billion and a maturity date of June 30, 2016, which is extendible with lender approval. As of March 6, 2014, approximately $0.4 billion was outstanding under our credit facility. In the event that our credit facility is not extended before June 30, 2016, all outstanding indebtedness thereunder will be repayable at that date. There is also a risk that our credit facility will not be renewed for the same principal amount or on the same terms. Any of these events could adversely affect our ability to fund our ongoing operations and, as repayment of such indebtedness has priority over the payment of dividends to Shareholders, to pay cash dividends to Shareholders.

We also currently have Senior Notes outstanding that are comprised of US$1,629 million principal amount of notes, Cdn$175 million principal amount of notes, £77 million principal amount of notes and €10 million principal amount of notes, which Senior Notes have maturity dates ranging between 2014 and 2025. In the event we are unable to repay or refinance these debt obligations (or if we must refinance these debt obligations on less favourable terms) it may adversely affect our ability to fund our ongoing operations and, as repayment of such indebtedness has priority over the payment of dividends to Shareholders, to pay cash dividends to Shareholders.

We are required to comply with covenants under our credit facilities and Senior Notes. In the event that we do not comply with covenants under one or more of these debt instruments, our access to capital could be restricted or repayment could be required, which could adversely affect our ability to fund our ongoing operations and, as repayment of such indebtedness has priority over the payment of dividends to Shareholders, to pay cash dividends to Shareholders.

We may incur additional indebtedness in the future.

From time to time, we may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise, and may adversely affect the market price of our Common Shares if investors consider our debt levels to be higher than that of our peers.

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.

In this Annual Information Form, 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 United States companies. Nevertheless, as part of Penn West's Amended Annual Report on Form 40-F for the year ended December 31, 2013 filed with the SEC, Penn West has disclosed proved reserves quantities using the standards contained in SEC Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with the U.S. Financial Accounting Standards Board, "Disclosures About Oil and Gas Producing Activities", which disclosure complies with the SEC's rules for disclosing oil and gas reserves.

We will require additional financing from time to time, which may result in dilution to Shareholders. If we are unable to obtain additional financing at all or on reasonable terms, the amount of cash dividends paid to Shareholders could be reduced.

In the normal course of making capital investments to maintain and expand our oil and gas reserves, additional Common Shares may be issued which may result in a decline in, including but not limited to, production per Common Share and reserves per Common Share. Additionally, from time to time, we may issue Common Shares from treasury in order to reduce debt and maintain a more optimal capital structure. Conversely, to the extent that external sources of capital, including the issuance of additional Common Shares, becomes limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and gas reserves will be impaired. To the extent that we are required to use additional cash flow from operating activities to finance capital expenditures or property acquisitions, or to pay debt service charges or reduce debt, the amount of cash dividends paid to Shareholders could be reduced.

Changes to royalty regimes may have a material and adverse impact on our financial condition.

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new, or modify the existing, royalty regime, which in each case may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic.

Our indebtedness may limit the amount of cash dividends that we are able to pay to our Shareholders, and if we default on our debt, the net proceeds of any foreclosure sale would be allocated to the repayment of our lenders and other creditors and only the remainder, if any, would be available for distribution to our Shareholders.

Amounts paid in respect of interest and principal on debt we have incurred will reduce funds available for the payment of dividends and reinvestment in our assets. Variations in interest rates and any scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Certain covenants in the agreements with our lenders may also limit the amount of cash dividends paid in certain circumstances. Increases in interest rates could also result in decreases to the market value of our Common Shares. Although we believe our credit facilities and other debt instruments will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations or that additional funds will be able to be obtained.

Our current credit agreement and other debt instruments are unsecured and we must comply with certain financial debt covenants. The lenders and other debt holders could, in the future, require security over a portion of or substantially all of our assets. Should this occur, in the event that we become unable to pay our debt service charges or otherwise commit an event of default such as bankruptcy, our lenders and other debt holders may foreclose on or require us to sell our oil and gas and other assets.

We depend upon our management and other key personnel and the loss of one or more of such individuals could negatively affect our business.

Shareholders depend upon the management of Penn West in respect of the administration and management of all matters relating to our operations. The success of our operations depends largely upon the skills and expertise of our senior management and other key personnel. Our continued success depends upon our ability to retain and recruit such personnel. Investors who are not willing to rely on the management of Penn West should not invest in our securities.

Changes in the regulation of the oil and gas industry may adversely affect our business.

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "Industry Conditions". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

The impact on us of claims of aboriginal title is unknown.

Aboriginal peoples have claimed aboriginal title and rights to portions of Western Canada. We are not aware that any material claims have been made in respect of our properties and assets; however, if a material claim arose and was successful this could have an adverse effect on our results of operations and business.

Delays in business operations could adversely affect the payment of cash dividends to Shareholders and the market price of the Common Shares.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of oil and natural gas properties, and by the operator to us, payments between any of such 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, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of properties, or the establishment by the operator of reserves for such expenses. Any one or more of these delays could adversely affect our ability to pay cash dividends to Shareholders and thus adversely affect the market price of our Common Shares.

Our operation of oil and natural gas wells, and our participation in oil and natural gas wells operated by others, could subject us to environmental claims and liability and/or increased compliance costs, all of which could affect the market price of our Common Shares and reduce the amount of cash dividends paid to Shareholders.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. In addition, such legislation sets out requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and legal 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 governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we will be in material compliance with current applicable environmental legislation, 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, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

We may be required to post a material security deposit under provincial liability management programs.

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. Although Manitoba does not have a liability management rating program similar to those found in the other western provinces, it does have similar programs that can require the posting of performance deposits and/or the payment of non-refundable levies. See "Industry Conditions - Liability Management Rating Programs".

Cash dividends paid on our Common Shares are variable and may be reduced or suspended entirely.

Cash flow from operating activities available for the payment of cash dividends to Shareholders can vary significantly from period to period for a number of reasons, including among other things: (i) our operational and financial performance (including fluctuations in the quantity of our oil, NGLs and natural gas production and the sales price that we realize for such production (after hedging contract receipts and payments)); (ii) fluctuations in the costs to produce oil, NGLs and natural gas, including royalty burdens, and to administer and manage Penn West; (iii) the amount of cash required or retained for debt service or repayment; (iv) amounts required to fund capital expenditures and working capital requirements; and (v) foreign currency exchange rates and interest rates. Certain of these amounts are, in part, subject to the discretion of the Board of Directors, which regularly evaluates Penn West's dividend payout with respect to anticipated cash flows, debt levels, capital expenditures plans and amounts to be retained to fund acquisitions and expenditures. In addition, our level of dividend per Common Share will be affected by the number of outstanding Common Shares.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the ability of Penn West to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Dividends on our Common Shares are neither preferential, cumulative nor stipulated by their terms to be at a fixed amount or rate. Dividends are declared by our Board in its sole discretion and are subject to change in accordance with our dividend policy. Our dividend policy is also subject to change in the Board's sole discretion. As a result, cash dividends may be reduced or suspended entirely depending on our operations and the performance of our assets. The market value of the Common Shares may deteriorate if we are unable to meet dividend expectations in the future, and that deterioration may be material. See "Dividends and Dividend Policy".

Our exploration and development activities may be delayed if drilling and related equipment is unavailable or if access to drilling locations is restricted. These events could have an adverse impact on our business.

Oil and natural gas exploration and development activities depend on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. To the extent we are not the operator of our oil and gas properties, we depend on such operators for the timing of activities related to such properties and are largely unable to direct or control the activities of the operators.

Changes in Canadian income tax legislation and other laws may adversely affect us and our Shareholders.

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders. Furthermore, tax authorities having jurisdiction over us or our Shareholders may disagree with how we calculate our income for tax purposes or could change administrative practises to our detriment or the detriment of our Shareholders.

We file all required income tax returns and believe that we are in compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of Penn West, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

We may incur material expenses complying with new or amended laws and regulations governing climate change.

Our exploration and production facilities and other operations and activities emit GHGs and require us to comply with GHG emissions legislation at the provincial and federal levels. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding. However, although it is not the case today, some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition. See "Industry Conditions – Climate Change Regulation".

We are exposed to potential liabilities that may not be covered, in part or in whole, by insurance.

Our involvement in the exploration and development of oil and natural gas properties could subject us to liability for pollution, blowouts, property damage, personal injury or other hazards. Prior to commencing operations, we obtain insurance in accordance with industry standards to address certain of these risks. Such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances, be insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects and will reduce the amount of funds otherwise available to us for the payment of cash dividends.

Future acquisitions, financings or other transactions and the issuance of securities pursuant to our equity compensation and other plans may result in Shareholder dilution.

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities, which may be dilutive to Shareholders. Shareholder dilution may also result from the issuance of Common Shares pursuant to our stock option plan ("**Option Plan**"), our Common Share Rights Incentive Plan ("**CSRIP"**) and our Dividend Reinvestment and Optional Common Share Purchase Plan ("**DRIP**"). For more information regarding our Option Plan, our CSRIP and our DRIP, see our most recent Information Circular and Proxy Statement, financial statements and related management's discussion and analysis filed on SEDAR at www.sedar.com.

In certain circumstances we may be required under applicable accounting standards to write down the value of the goodwill recorded on our balance sheet and incur a non-cash charge against income.

IFRS requires that goodwill balances be tested at least annually for impairment and that any impairment be charged to income. A reduction in reserves, a decline in commodity prices, and/or a reduction in the Common Share price could indicate goodwill impairment. As at December 31, 2013, we had approximately $1.9 billion recorded on our balance sheet as goodwill arising from historical acquisitions. An impairment would result in a write-down of this goodwill value and a non-cash charge against our income, which may be viewed unfavourably by investors and adversely impact the market price of our Common Shares. Goodwill impairments are not allowed to be reversed in future periods. The calculation of impairment value is subject to management estimates and assumptions.

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

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production and other parties. Poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially affecting our funding requirements or delaying the program and the results of such program until we find a suitable alternative partner.

In the normal course of our operations, we are exposed to litigation, which if determined adversely, could have a material and adverse impact on us.

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment, securities law matters (such as our public disclosures), and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations.

Non-Residents may be subject to additional taxation by Canadian or foreign governments that may adversely affect them.

The Tax Act and the tax treaties between Canada and other countries may impose additional withholding or other taxes on the cash dividends or other property paid or distributed by us to Shareholders who are Non-Residents, and these taxes may change from time to time.

We do not operate all of our properties and facilities. Therefore, our results of operations may be adversely affected by pipeline interruptions and apportionments, railway interruptions and/or the actions or inactions of third party operators, any of which could cause delays in receiving our revenues and cause us to incur additional expenses, which could in turn adversely affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

We deliver our products through gathering and processing facilities, pipeline systems and by railway systems, some of which we do not own. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems or railway lines, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. As a result, producers are increasingly turning to rail as an alternative means of transportation and competition for contracting rail capacity is increasing. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition, results of operations and cash flows.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of our production may, from time to time, be processed through facilities owned by third parties that we do not control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinue or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

Other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Lower oil and gas prices and higher costs increase the risk of write-downs of our oil and gas property assets and goodwill.

Under IFRS, when indicators of impairment exist, the carrying value of our Property, Plant and Equipment ("**PP&E**") and Exploration and Evaluation ("**E&E**") assets is compared to its recoverable amount. The recoverable amount is defined as the higher of the fair value less cost to sell or value in use. A decline in oil and gas prices may be an indicator of impairment and may result in a write-down of the value of our assets. While these write-downs would not affect cash flow from operations, the charge to earnings may be viewed unfavourably by investors and adversely impact the market price of our Common Shares. PP&E or E&E asset write-downs may also be reversed to earnings in future periods should the conditions that caused impairment reverse.

We may not be able to maintain the confidentiality of sensitive information in business dealings with third parties, and our remedies for breaches of confidentiality may not fully compensate us for our losses.

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

Our inability to manage growth could adversely affect our business and our Shareholders.

We may be subject to growth related risks, including capacity constraints and pressures on our internal systems and controls. These constraints and pressures could result from, among other things, the completion of large acquisitions. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth could have a material adverse impact on our business, operations and prospects.

Our cash dividends are declared in Canadian dollars and Non-Resident investors are therefore subject to foreign exchange risk that could adversely affect the amount of cash dividends received by them.

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

An unforeseen defect in the chain of title to our oil and natural gas producing properties may arise to defeat our claim, which could have an adverse effect on the market price of our Common Shares and could reduce the amount of cash dividends paid to our Shareholders.

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim, which could result in a reduction in the amount of revenue received by us and consequently the funds available for the payment of cash dividends to Shareholders. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties that we control that, if successful or made into law, could impair our activities on such properties and result in a reduction of the revenue received by us.

The ability of residents of the United States to enforce civil remedies against us and our directors, officers and experts may be limited.

Penn West is organized under the laws of Alberta, Canada and our principal places of business are in Canada. Most of our directors and officers and the experts named herein are residents of Canada, and a substantial portion of our assets and all or a substantial portion of the assets of most 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 those directors, officers and experts who are not residents of the United States or to enforce against them judgments of 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 against any of our directors, officers or 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 the securities laws of any state within the United States.

The termination or expiration of licenses and leases through which we or our industry partners hold our interests in petroleum and natural gas substances could adversely affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

Our properties are held in the form of licenses and leases and working interests in licenses and leases. If we or the holder of the license or lease fail to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that all of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse effect on our results of operations and business.

The global financial crisis and severe recession experienced in 2008 and 2009 had an adverse effect on commodity prices and on our access to capital at that time. Should one or both of these conditions be experienced again in the future, they could have a material adverse effect on our results of operations and financial condition, which in turn could negatively affect the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

The global financial crisis and severe recession experienced in 2008 and 2009, which included disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, caused significant volatility to commodity prices and a loss of confidence in the broader U.S. and global credit and financial markets, resulting in the collapse of some, and government intervention in many, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, increased credit losses and tighter credit conditions. Notwithstanding various actions taken by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially (although credit markets and stock markets have since improved significantly). These factors negatively impacted company valuations and are expected to continue to impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of, among other things, market uncertainties over the supply and demand of these commodities due to the current state of the world economies and the ongoing global credit and liquidity concerns. As a result of the weakened global economic situation, we (and all other oil and gas entities) may experience restricted access to capital and increased borrowing costs in the future. To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition, results of operations and dividends may be materially and adversely affected as a result.

Our directors and management may have conflicts of interest that may create incentives for them to act contrary to or in competition with the interests of our Shareholders.

Certain directors and officers of Penn West are engaged in, and will continue to engage in, other activities in the oil and natural gas industry and, as a result of these and other activities, the directors and officers of Penn West may become subject to conflicts of interest. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director must disclose his interest in such contract or agreement and must refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA and our Code of Business Conduct and Ethics and our Code of Ethics for Directors, Officers and Senior Financial Management. See "Directors and Executive Officers of Penn West – Conflicts of Interest".

A decrease in the fair market value of our hedging instruments could result in a non-cash charge against our income under applicable accounting standards.

Under IFRS, accounting for financial instruments may result in non-cash charges against income as a result of reductions in the fair market value of hedging instruments. A decrease in the fair market value of the hedging instruments as a result of fluctuations in commodity prices and/or foreign exchange rates may result in a non-cash charge against income, which may be viewed unfavourably in the market.

We may in the future expand our operations into new geographical regions where our existing management does not have experience. In addition, we may in the future acquire new types of energy related assets in respect of which our existing management does not have experience. Any such expansion or acquisition could result in our exposure to new risks that if not properly managed could ultimately have an adverse effect on our business, the market price of our Common Shares and the amount of cash dividends paid to our Shareholders.

The operations and expertise of our management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future, we may acquire or develop oil and gas properties outside of this geographic area. In addition, we could acquire other energy related assets, such as upgraders or pipelines. Expansion of our activities into new areas may present new risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Our information assets and critical infrastructure may be subject to destruction, theft, cyber-attacks or misuse by unauthorized parties

We are subject to a variety of information technology and/or system risks as a part of our normal course operations. Although we have security measures in place that are designed to mitigate these risks, a breach of our security measures and/or a loss of information could occur and result in a loss of material and/or confidential information and/or a disruption to our business activities. The significance of any such event is difficult to quantify, but may in certain circumstances be material and adverse to our financial condition and results of operations and thus the market price of our Common Shares.

There might not always be an active trading market in the United States and/or Canada for the Common Shares.

While there is currently an active trading market for the Common Shares in both the United States and Canada, we cannot guarantee that an active trading market will be sustained in either country. If an active trading market in the Common Shares is not sustained, the trading liquidity of the Common Shares will be limited and the market value of the Common Shares may be reduced.

The market price of our Common Shares has been and will likely continue to be volatile, and may at times be less than our net asset value per Common Share.

The trading price of securities of oil and natural gas issuers is subject to substantial volatility, and is often based on factors both related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors.

Our net asset value from time to time will vary depending upon a number of factors beyond our control, including oil and gas prices. The trading price of the Common Shares from time to time is determined by a number of factors, some of which are beyond our control and such trading price may be greater or less than our net asset value. The price at which our Common Shares will trade cannot be accurately predicted.

We cannot assure you that the dividends you receive over the life of your investment will meet or exceed your initial capital investment, which is at risk.

Common Shares will have no value when the underlying petroleum and natural gas properties can no longer be economically produced and, as a result, cash dividends may not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Dividends can represent a *return of* or a *return on* Shareholders' capital.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only contracts that are material to us and that were entered into by us or one of our Subsidiaries within the most recently completed financial year or before the most recently completed financial year but which are still material and are still in effect, are the following:

(a) the amended and restated credit agreement dated June 27, 2011 (as amended by first amending agreement dated as of June 15, 2012) among Penn West and certain lenders and other parties in respect of Penn West's $3.0 billion syndicated credit facility, which agreement is described under "Capitalization of Penn West – Debt Capital – Credit Facility";

(b) the note purchase agreement dated May 31, 2007 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of our Series A, Series B, Series C and Series D Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes";

(c) the note purchase agreement dated May 29, 2008 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of our Series E, Series F, Series G and Series H Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes";

(d) the note purchase agreement dated July 31, 2008 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of our Series I Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes";

(e) the note purchase agreement dated May 5, 2009 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of our Series J, Series K, Series L, Series M, Series N, Series O and Series P Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes";

(f) the note purchase agreement dated March 16, 2010 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of our Series Q, Series R, Series S, Series T, Series U and Series V Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes";

(g) the note purchase agreement dated December 2, 2010 (as amended by first amending agreement dated as of December 2, 2010) among Penn West and the holders of our Series W, Series X, Series Y, Series Z, Series AA and Series BB Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes"; and

(h) the note purchase agreement dated November 30, 2011 among Penn West and the holders of our Series CC, Series DD, Series EE and Series FF Senior Notes, which agreement is described under "Capitalization of Penn West – Debt Capital – Senior Notes".

Copies of each of these agreements have been filed on SEDAR at www.sedar.com.

Changes to Contracts

There is currently no aspect of our business that we reasonably expect to be materially affected in the current financial year by the renegotiation or termination of contracts or sub-contracts.

Economic Dependence

We are not currently a party to any contract on which our business is substantially dependent, including any contract to sell the major part of our products or to purchase the major part of our requirements for goods, services or raw materials, or any franchise or licence or other agreement to use a patent, formula, trade secret, process or trade name on which our business depends.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that Penn West is or was a party to, or that any of Penn West's property is or was the subject of, during the most recently completed financial year, that were or are material to Penn West, and there are no such material legal proceedings that Penn West knows to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" by us if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10 percent of our current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, we have included the amount involved in the other proceedings in computing the percentage.

There were no: (i) penalties or sanctions imposed against Penn West by a court relating to securities legislation or by a security regulatory authority during our most recently completed financial year; (ii) any other penalties or sanctions imposed by a court or regulatory body against Penn West that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements Penn West entered into before a court relating to securities legislation or with a securities regulatory authority during Penn West's most recently completed financial year.

TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares in Canada is CST Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario. The co-transfer agent and registrar for the Common Shares in the United States is Computershare Shareowner Services at its principal offices in Jersey City, New Jersey.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of any director or executive officer of Penn West, any person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10 percent of the outstanding Common Shares, or any known associate or affiliate of any such person, in any transaction within Penn West's three most recently completed financial years or during our current financial year that has materially affected or is reasonably expected to materially affect Penn West.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a report, valuation, statement or opinion made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year, other than Sproule, GLJ Petroleum Consultants Ltd and Deloitte LLP, independent engineering evaluators retained by us in 2013 (each an "**Expert**", and collectively, the "**Experts**"), and KPMG LLP ("**KPMG**"), our auditors.

There were no registered or beneficial interests, direct or indirect, in any securities or other property of Penn West or of one of our associates or affiliates: (i) held by an Expert and by the "designated professionals" (as defined in Form 51-102F2 – *Annual Information Form*) of the Expert, when that Expert prepared the relevant report, valuation, statement or opinion; (ii) received by an Expert and by the "designated professionals" of that Expert, after the preparation of the relevant report, valuation, statement or opinion; or (iii) to be received by an Expert and by the "designated professionals" of that Expert; except with respect to the ownership of our Common Shares, in which case the person's or company's interest in our Common Shares represents less than one percent of our outstanding Common Shares. The foregoing does not include registered or beneficial interests, direct or indirect, held through mutual funds.

KPMG are the auditors of the Penn West and have confirmed that they are independent with respect to Penn West within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations, and also that they are independent accountants with respect to Penn West under all relevant US professional and regulatory standards.

No director, officer or employee of an Expert or KPMG is or is expected to be elected, appointed or employed as a director, officer or employee of Penn West or of any associate or affiliate of Penn West.

ADDITIONAL INFORMATION

Additional information relating to Penn West may be found on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Penn West's securities and securities authorized for issuance under equity compensation plans, is contained in Penn West's Information Circular for its most recent annual meeting of securityholders that involved the election of directors. Additional financial information is provided in Penn West's restated financial statements and restated management's discussion and analysis for its most recently completed financial year.

Any document referred to in this Annual Information Form and described as being filed on SEDAR at www.sedar.com and on EDGAR at www.sec.gov (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us by contacting our Investor Relations Department by telephone (toll free: 1-888-770-2633) or by email (investor_relations@pennwest.com).

APPENDIX A-1

AMENDED REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

(Form 51-101F3)

Management of Penn West Petroleum Ltd. ("**Penn West**") is responsible for the preparation and disclosure of information with respect to Penn West's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

An independent qualified reserves evaluator/auditor has evaluated/audited Penn West's reserves data. The report of the independent qualified reserves evaluator/auditor is presented below.

The Reserves Committee of the Board of Directors of Penn West has:

(a) reviewed Penn West's procedures for providing information to the independent qualified reserves evaluator/auditor;

(b) met with the independent qualified reserves evaluator/auditor to determine whether any restrictions affected the ability of the independent qualified reserves evaluator/auditor to report without reservation, and, in the event of a proposal to change the independent qualified reserves evaluator/auditor, to inquire whether there had been disputes between the previous independent qualified reserves evaluator/auditor and management; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator/auditor.

The Reserves Committee of the Board of Directors has reviewed Penn West'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 amended Form 51-101F1 containing reserves data and other oil and gas information;

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

(c) the content and filing of this amended report.

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

(signed) *"David E. Roberts"*
President and Chief Executive Officer

(signed) *"David A. Dyck"*
Senior Vice President and Chief Financial Officer

(signed) *"Richard L. George"*
Director and Chair of the Operations and Reserves Committee

(signed) *"Jay W. Thornton"*
Director and Member of the Operations and Reserves Committee

September 17, 2014

APPENDIX A-2

REPORT ON RESERVES DATA

(Form 51-101F2)

To the Board of Directors of Penn West Petroleum Ltd. ("**Penn West**"):

1. We have evaluated/audited Penn West's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of Penn West's management. Our responsibility is to express an opinion on the reserves data based on our evaluation/audit.

   We carried out our evaluation/audit in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation/audit to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation/audit also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Penn West evaluated/audited by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and audited and reported on to Penn West's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation / Audit Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue (millions before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	January 30, 2014	Canada	$2,252	$6,627	$-	$8,879
Sproule Associates Limited	January 30, 2014	USA	$-	$-	$-	$-
Totals			$2,252	$6,627	$-	$8,879

5. In our opinion, the reserves data respectively evaluated or audited 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.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. 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:

(signed) *"Sproule Associates Limited"*
Sproule Associates Limited
Calgary, Alberta, Canada
March 6, 2014

APPENDIX A-3

AMENDED STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Our amended statement of reserves data and other oil and gas information dated September 17, 2014 is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2013 and the preparation date of the Statement is March 6, 2014. The Amended Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 and the Report on Reserves Data by Sproule on Form 51-101F2 are attached as Appendices A-1 and A-2, respectively, to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation and audit prepared by Sproule with an effective date of December 31, 2013 contained in the Engineering Report. The reserves data summarizes our oil, natural gas liquids and natural gas reserves and the net present values of future net revenue from these reserves using forecast prices and costs, not including the impact of any hedging activities. The reserves data conforms to the requirements of NI 51-101. We engaged Sproule to evaluate approximately 75 percent and to audit approximately 25 percent of our proved and proved plus probable reserves, based on the net present value of future net revenue of such reserves discounted at 10 percent. See also "Notes to Reserves Data Tables" below.

The vast majority of our proved plus probable reserves are located in Canada in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories. We also have very minor proved plus probable reserves interests in the United States in Wyoming. The reserves information presented below does not report reserves that are located in the United States separately. Our properties located in the United States have proved plus probable gross reserves representing less than one percent of our total proved plus probable gross reserves , and have a before tax net present value discounted at 10 percent representing less than one percent of the total before tax net present value of our proved plus probable gross reserves .

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast price and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

BOEs 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 as compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is misleading as an indication of value.

For more information as to the risks involved, see "Risk Factors".

Reserves Data

SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL AND BITUMEN	
RESERVES CATEGORY	Gross (MMbbl)	Net (MMbbl)	Gross (MMbbl)	Net (MMbbl)
PROVED				
Developed Producing	141	122	38	34
Developed Non-Producing	5	4	-	-
Undeveloped	72	61	4	3
TOTAL PROVED	218	187	42	38
PROBABLE	96	80	40	35
TOTAL PROVED PLUS PROBABLE	314	267	82	73

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Bcf)	Net (Bcf)	Gross (MMbbl)	Net (MMbbl)
PROVED				
Developed Producing	585	517	22	16
Developed Non-Producing	30	25	1	1
Undeveloped	142	123	7	5
TOTAL PROVED	757	664	30	22
PROBABLE	366	316	13	9
TOTAL PROVED PLUS PROBABLE	1,123	980	42	31

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (MMboe)	Net (MMboe)
PROVED		
Developed Producing	299	259
Developed Non-Producing	11	9
Undeveloped	106	90
TOTAL PROVED	415	358
PROBABLE	209	176
TOTAL PROVED PLUS PROBABLE	625	534

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2013
BEFORE INCOME TAXES DISCOUNTED AT (%/year)
FORECAST PRICES AND COSTS

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	Unit Value Before Income Tax Discounted at 10%/year[(1)] ($/bbl)	($/Mcf)
PROVED							
Developed Producing	9,826	6,927	5,412	4,487	3,864	20.93	3.49
Developed Non-Producing	279	202	156	127	107	17.62	2.94
Undeveloped	3,465	1,923	1,157	714	432	12.84	2.14
TOTAL PROVED	13,570	9,052	6,726	5,329	4,403	18.81	3.14
PROBABLE	7,991	3,785	2,153	1,353	899	12.22	2.04
TOTAL PROVED PLUS PROBABLE	21,561	12,836	8,879	6,682	5,302	16.64	2.77

Note:

(1) The unit values are based on net reserve volumes.

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2013
AFTER INCOME TAXES DISCOUNTED AT (%/year)
FORECAST PRICES AND COSTS

RESERVES CATEGORY	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)
PROVED					
Developed Producing	8,522	6,226	4,986	4,208	3,671
Developed Non-Producing	208	153	120	99	85
Undeveloped	2,583	1,387	789	442	222
TOTAL PROVED	11,313	7,765	5,895	4,750	3,978
PROBABLE	5,950	2,790	1,558	953	611
TOTAL PROVED PLUS PROBABLE	17,264	10,555	7,453	5,703	4,589

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (MM$)	ROYALTIES (MM$)	OPERATING COSTS (MM$)	DEVELOPMENT COSTS (MM$)	ABANDONMENT AND RECLAMATION COSTS (MM$)	FUTURE NET REVENUE BEFORE FUTURE INCOME TAXES (MM$)	FUTURE INCOME TAXES (MM$)	FUTURE NET REVENUE AFTER FUTURE INCOME TAXES (MM$)
Proved Reserves	32,746	4,448	11,666	2,249	813	13,570	2,257	11,313
Proved Plus Probable Reserves	50,798	7,322	17,495	3,506	915	21,561	4,297	17,264

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	UNIT VALUE[3] ($/bbl)	UNIT VALUE[3] ($/Mcf)
Proved Reserves	Light and Medium Crude Oil[1]	5,175	21.44	3.57
	Heavy Oil and Bitumen[1]	865	21.75	3.63
	Natural Gas[2]	607	9.26	1.54
	Non-Conventional Oil and Gas Activities	79	7.58	1.26
	TOTAL	6,726	18.81	3.14
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	6,735	19.52	3.25
	Heavy Oil and Bitumen[1]	1,246	16.58	2.76
	Natural Gas[2]	799	8.71	1.45
	Non-Conventional Oil and Gas Activities	99	4.65	0.78
	TOTAL	8,879	16.64	2.77

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas and by-products from oil wells.
(3) Revenues and costs not related to a specific production group have been allocated proportionately to each production group. The unit values are based on net reserve volumes.

Notes to Reserves Data Tables

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserves estimates presented in the Engineering Report are based on the definitions and guidelines contained in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**"). A summary of those definitions are set forth below:

Reserves Categories

Reserves are estimated remaining 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.

(d) **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.

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

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

Development and Production Status

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

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

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

   (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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) to which they are assigned.

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

Levels of Certainty for Reported Reserves

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

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

(b) at least a 50 percent 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 are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

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

3. Forecast prices and costs

NI 51-101 defines "forecast prices and costs" as future prices and costs that are: (i) generally acceptable 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 we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (i).

The forecast cost and price assumptions include increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. The crude oil, natural gas and natural gas liquids benchmark reference pricing, inflation rates and exchange rates utilized in the Engineering Report are set forth below. The price assumptions set forth below were provided by Sproule.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

	OIL					EDMONTON LIQUIDS PRICES				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40ºAPI ($Cdn/bbl)	Western Canada Select 20.5ºAPI ($Cdn/bbl)	Cromer LSB 35ºAPI ($Cdn/bbl)	NATURAL GAS AECO ($Cdn/MMbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	INFLATION RATES(1) %/year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast										
2014	94.65	92.64	77.81	90.64	4.00	45.78	69.05	103.50	1.5	0.94
2015	88.37	89.31	75.02	87.31	3.99	44.14	66.57	99.78	1.5	0.94
2016	84.25	89.63	75.29	87.63	4.00	44.30	66.81	100.14	1.5	0.94
2017	95.52	101.62	85.36	99.62	4.93	50.22	75.74	113.53	1.5	0.94
2018	96.96	103.14	86.64	101.14	5.01	50.98	76.88	115.24	1.5	0.94
2019	98.41	104.69	87.94	102.69	5.09	51.74	78.03	116.97	1.5	0.94
2020	99.89	106.26	89.26	104.26	5.18	52.52	79.20	118.72	1.5	0.94
2021	101.38	107.86	90.60	105.86	5.26	53.30	80.39	120.50	1.5	0.94
2022	102.91	109.47	91.96	107.47	5.35	54.10	81.60	122.31	1.5	0.94
2023	104.45	111.12	93.34	109.12	5.43	54.92	82.82	124.14	1.5	0.94
Thereafter	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	-	-

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average actual prices realized, including hedging activities, for the year ended December 31, 2013 were $3.44/Mcf for natural gas, $88.01/bbl for light and medium crude oil, $65.12/bbl for heavy oil and $51.76/bbl for natural gas liquids.

4. Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

	Forecast Prices and Costs	
Year	Proved Reserves (MM$)	Proved Plus Probable Reserves (MM$)
2014	704	840
2015	973	1,533
2016	419	726
2017	58	149
2018	35	92
2019 and subsequent	60	166
Total: Undiscounted for all years	2,249	3,506

We currently expect to fund the development costs of our reserves primarily through internally-generated funds flow. There can be no guarantee that funds will be available to develop all of our reserves or that we will allocate funding to develop all of the reserves attributed in the Engineering Report. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to our reserves. The interest and other costs of any external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not currently expect that interest or other funding costs could make development of any of our properties uneconomic.

5. Estimated future well abandonment costs related to reserve wells have been taken into account by Sproule in determining the aggregate future net revenue therefrom.

6. The forecast price and cost assumptions assume the continuance of current laws and regulations.

7. All factual data supplied to Sproule was accepted as represented. No field inspection was conducted.

8. The estimates of future net revenue presented in the tables above do not represent fair market value.

Reconciliations of Changes in Reserves

The following table sets forth the reconciliation of our gross reserves as at December 31, 2013, using forecast price and cost estimates derived from the Engineering Report.

RECONCILIATION OF
COMPANY GROSS RESERVES
BY PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL[1]			HEAVY OIL AND BITUMEN[1]			ASSOCIATED AND NON-ASSOCIATED GAS[1]		
FACTORS	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	Gross Proved (Bcf)	Gross Probable (Bcf)	Gross Proved Plus Probable (Bcf)
December 31, 2012	243	108	351	46	44	90	773	413	1,186
Extensions	-	1	1	1	-	1	13	28	41
Infill drilling	14	7	21	2	-	2	12	6	18
Improved Recovery	-	5	6	-	-	1	-	2	2
Technical Revisions	(9)	(17)	(26)	4	(2)	2	121	(8)	113
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	1	-	1
Dispositions	(11)	(8)	(19)	(7)	(3)	(9)	(46)	(76)	(121)
Economic Factors	1	-	2	-	-	1	(8)	1	(7)
Production	(22)	-	(22)	(6)	-	(6)	(109)	-	(109)
December 31, 2013	218	96	314	41	40	82	757	366	1,123

FACTORS	NATURAL GAS LIQUIDS(1) Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	TOTAL OIL EQUIVALENT(1) Gross Proved (MMboe)	Gross Probable (MMboe)	Gross Proved Plus Probable (MMboe)
December 31, 2012	27	11	38	445	231	676
Extensions	-	-	-	3	5	9
Infill drilling	1	-	1	18	9	27
Improved Recovery	-	-	-	1	6	7
Technical Revisions	6	2	8	22	(19)	4
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(1)	(1)	(1)	(26)	(24)	(50)
Economic Factors	-	-	-	-	-	1
Production	(4)	-	(4)	(49)	-	(49)
December 31, 2013	30	13	42	415	209	625

Notes:

(1) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. Undeveloped reserves must fully meet the requirements of the reserves category (proved or probable) to which they are assigned.

In some cases, it will take longer than two years to develop Penn West's undeveloped reserves. Penn West plans to develop approximately three-quarters of the proved undeveloped reserves in the Engineering Report over the next two years and the significant majority of the proved undeveloped reserves over the next five years. Penn West plans to develop approximately one-half of the probable undeveloped reserves in the Engineering Report over the next two years and the significant majority of the probable undeveloped reserves over the next five years. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing and/or operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals).

Proved Undeveloped Reserves

The following table discloses, for each product type, the gross volumes of proved undeveloped reserves that were first attributed in each of the most recent four financial years.

Year	Light and Medium Oil (MMbbl)		Heavy Oil and Bitumen (MMbbl)		Natural Gas (Bcf)		NGLs (MMbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2010	16	51	-	1	28	83	1	2
2011	39	78	2	2	60	88	3	4
2012	24	76	1	2	24	100	2	5
2013	13	72	1	4	25	142	1	7

Sproule has assigned 106 MMboe of proved undeveloped reserves in the Engineering Report under forecast prices and costs, together with $2,123 million of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Engineering Report accounts for $1,613 million, or 76 percent, of the total forecast undiscounted capital expenditures for proved undeveloped reserves. These figures increase to $2,100 million, or 99 percent, during the first five years of the Engineering Report. The majority of our proved undeveloped reserves evaluated in the Engineering Report are attributable to future oil development from known pools and enhanced oil recovery projects.

Probable Undeveloped Reserves

The following table discloses, for each product type, the gross volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (MMbbl)		Heavy Oil and Bitumen (MMbbl)		Natural Gas (Bcf)		NGLs (MMbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2010	11	36	1	1	52	112	-	2
2011	22	51	8	9	125	207	2	4
2012	27	58	24	34	53	184	1	4
2013	12	49	-	31	33	146	1	4

Sproule has assigned 108 MMboe of probable undeveloped reserves in the Engineering Report under forecast prices and costs, together with $1,218 million of associated undiscounted future capital expenditures. Probable undeveloped capital spending in the first two forecast years of the Engineering Report accounts for $677 million, or 56 percent, of the total forecast undiscounted future capital expenditures for probable undeveloped reserves. These figures increase to $1,115 million, or 92 percent, during the first five years of the Engineering Report. The probable undeveloped reserves evaluated in the Engineering Report are primarily associated with proved undeveloped reserve assignments but have a less likely probability of being recovered than such associated proved undeveloped reserve assignments.

Significant Factors or Uncertainties Affecting Reserves Data

The development schedule for our undeveloped reserves is based on forecast price assumptions for the determination of economic projects. The actual market prices for oil and natural gas may be significantly lower or higher resulting in some projects being delayed or accelerated, as the case may be. See "Risk Factors".

We do not anticipate that any significant economic factors or other significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control.

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs in respect of surface leases, wells, facilities and pipelines (collectively, "**A&R Costs**") are primarily comprised of abandonment, decommissioning, remediation and reclamation costs. A&R Costs are estimated using our experience conducting annual abandonment and reclamation programs over the past several years, the use of external consultants, and the use of comparisons to A&R Cost estimates obtained from the Alberta regulatory authorities.

Penn West reviews its suspended or standing well bores for reactivation, recompletion or sale opportunities. Wellbores that do not meet this criterion become part of our overall wellbore abandonment program. A portion of our liability issues are retired every year and facilities are generally decommissioned subsequent to the time when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and where possible, opportunities for multi-location programs and continuous operations to reduce costs.

As of December 31, 2013, we expect to incur future A&R Costs in respect of approximately 17,085 net well bores, 2,182 facilities and 27,480 kilometres of pipelines. On an undiscounted, inflated basis, approximately 38 percent of A&R costs relate to well bores, 21 percent to facilities and 41 percent to pipelines. The total amount of A&R Costs, net of estimated salvage values, we expect to incur, including wells that extend beyond the 50-year limit in the Engineering Report, are summarized in the following table:

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted (MM$)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% (MM$)
Total liability as at December 31, 2013	6,635	186
Anticipated to be paid in 2014	75	68
Anticipated to be paid in 2015	72	60
Anticipated to be paid in 2016	70	53
Total anticipated to be paid in 2014, 2015 and 2016	217	181

The above table includes certain A&R Costs, net of estimated salvage values, not included in the Engineering Report and not deducted in estimating future net revenue as disclosed above. Escalated at two percent and undiscounted, the A&R Costs not deducted were $727 million, and escalated at two percent and discounted at 10 percent, these A&R Costs were $10 million.

OTHER OIL AND GAS INFORMATION

Description of Our Properties, Operations and Activities in Our Major Operating Regions

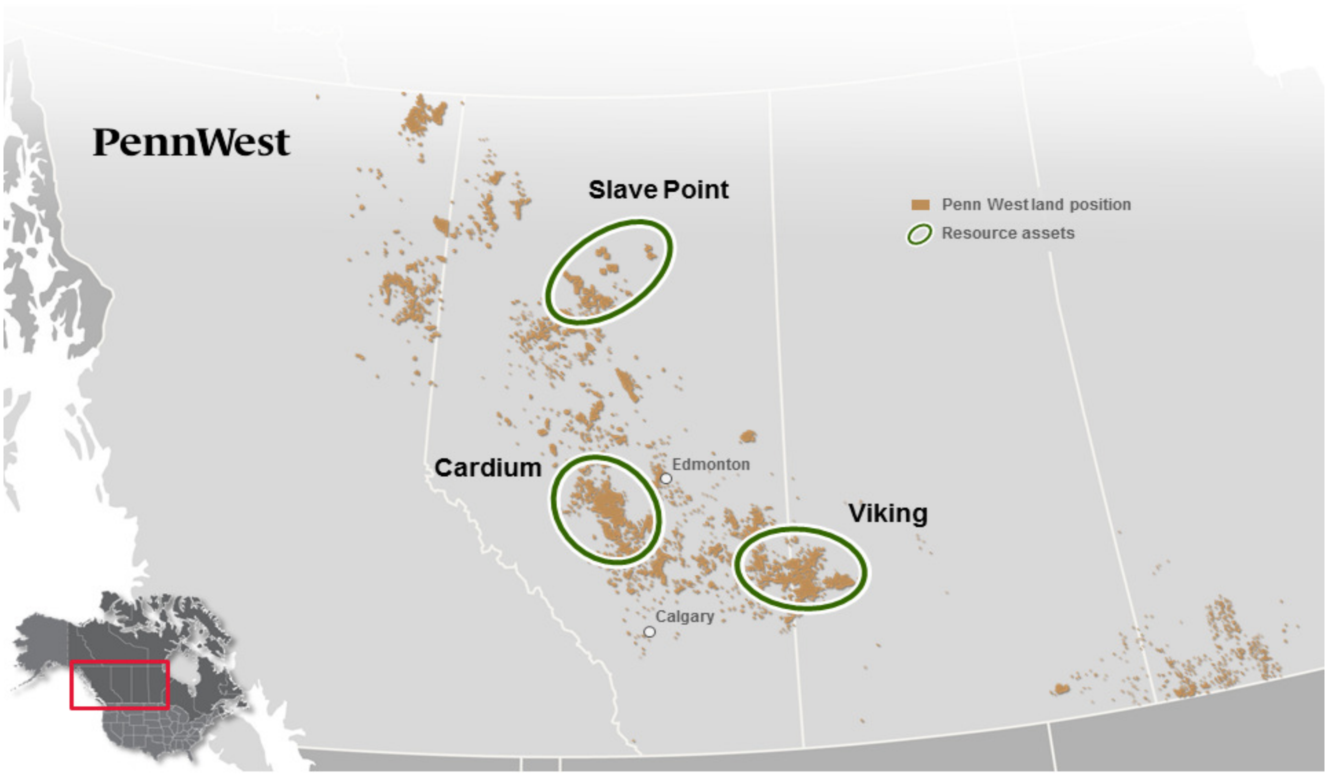
Introduction

Penn West participates in the exploration for, and the development and production of, oil and natural gas principally in western Canada. Our portfolio of properties as at December 31, 2013 includes both unitized and non-unitized oil and natural gas production. In general, the properties contain long-life, low-decline-rate reserves and include interests in several major oil and gas fields. The majority of our proved plus probable reserves are located in Canada in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories. We also have minor proved plus probable reserves interests in the United States in Wyoming.

Major Operating Regions

Our production and reserves are attributed to approximately 160 producing properties. No single property accounts for more than seven percent of our proved plus probable reserves. Penn West's operations are currently focused on light-oil development.

The following map illustrates Penn West's major operating regions as at December 31, 2013.



The following is a description of our principal oil and natural gas properties and related operations and activities as at December 31, 2013. Information in respect of gross and net acres and well counts are as of December 31, 2013 and information in respect of production is for the year ended December 31, 2013, except where indicated otherwise. **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.**

Cardium Resource Play

The Cardium resource play is located in west central Alberta and extends from Calgary to Grande Prairie, Alberta. At December 31, 2013, Penn West had over 600,000 net acres of developed and undeveloped land in this resource play. Penn West's holdings in the Cardium include, among others, lands in the Willesden Green, Alder Flats and West Pembina areas. In 2013 Penn West continued to focus on cost reductions and cycle time improvements in the area. Development activity was focused on the Lodgepole and Crimson Lake areas of the play, which resulted in a total of 25 net wells being drilled. In 2014, Penn West's capital budget is focused on expanding waterflood programs in the core areas of the play along with increasing its development activities, primarily in the Lodgepole and Crimson Lake areas.

Slave Point Resource Play

The Slave Point resource play is a tight, light-oil play situated north and northwest of Edmonton that extends through north-central Alberta. At December 31, 2013, Penn West had approximately 300,000 net acres of developed and undeveloped land in this resource play. In 2013, Penn West continued to focus its capital programs on selective drilling in the Sawn Lake, Otter and Red Earth areas. A waterflood pilot was initiated in the Otter area with further expansion planned for 2014. For 2014, Penn West has plans for a low-risk, development program continuing in the Sawn Lake, Otter and Red Earth areas of the play along with continuing its waterflood program as mentioned above in Otter and a new pilot in Sawn Lake.

Viking Resource Play

The Viking resource play is located in western Saskatchewan and east central Alberta and is divided into two distinct plays; the Viking oil play in Saskatchewan and a combined oil and natural gas play in eastern Alberta. Penn West has a significant land position on the oil side of the play with approximately 450,000 net acres of developed and undeveloped land at December 31, 2013. Penn West completed a significant drilling program in 2013 concentrated on oil development, primarily in the Dodsland area resulting in 75 net wells being drilled. Through this program, Penn West was able to significantly reduce both costs and cycle times to become an industry leader in the area. In 2014, Penn West plans to further develop the Dodsland area and assess the potential for down spacing along with the implementation of a waterflood program in the Avon Hills area.

Enhanced Oil Recovery

Penn West believes that recent results in its key plays and continuing advancements in drilling, completions and other technologies will enable it to pursue various enhanced recovery techniques aimed at increasing oil recovery rates in several of its large plays. During 2013, Penn West continued to expand its enhanced recovery programs primarily through the use of waterflood techniques as outlined above. In 2014, Penn West plans to continue to build on these results and expand on existing waterflood projects and initiate others in most of its key areas.

Additional Information

None of our important properties, plants, facilities or installations are subject to any material statutory or other mandatory relinquishments, surrenders, back-ins or changes in ownership.

We do not have any important properties to which reserves have been attributed and which are capable of producing but which are not producing.

2014 Capital Budget

Penn West's capital budget has been revised from $900 million to $820 million to reflect the reclassification of $80 million of the budget from capital expenditures to operating expenses in connection with the restatement of certain of our historical financial statements as described in our September 18, 2014 press release "Penn West Provides Results of Internal Review of Accounting Practices, Files Restated Financial Statements and Confirms no Impact on Strategic Direction". There was no impact on planned development capital activities for 2014 as a result of this adjustment. Total budgeted development capital is approximately $700 million with the remainder allocated to base infrastructure improvement. Of the development capital budget, approximately $570 million is allocated to light-oil development, including approximately $270 million to the Cardium play and approximately $150 million to each of the Viking and Slave Point plays. The 2014 capital program includes allocations to longer lead time production projects, including drilling wells in the Cardium and Slave Point areas and making significant investments in waterflood programs in its key areas. Penn West expects to drill approximately 210 net wells in 2014.

The primary components of our programs are described above under the heading "Major Operating Regions". See also "Description of our Business – General Development of the Business – 2014 Developments – 2014 Capital Expenditure Budget and Production Guidance".

Oil And Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2013.

	Producing				Non-Producing		Total	
	Oil		Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	7,349	4,650	4,322	2,903	6,751	4,366	18,422	11,919
British Columbia	144	63	769	322	491	209	1,404	594
Saskatchewan	3,398	2,316	331	261	1,995	1,354	5,724	3,930
Manitoba	498	461	-	-	43	41	541	502
Northwest Territories	8	1	-	-	31	5	39	6
Wyoming	100	36	-	-	223	98	323	134
Total	11,497	7,527	5,422	3,486	9,534	6,073	26,453	17,085

Properties with no Attributed Reserves

The following table sets out the unproved properties in which we had an interest as at December 31, 2013.

	Unproved Properties (thousands of acres)	
	Gross	Net
Alberta	1,932	1,449
British Columbia	612	292
Saskatchewan	88	79
Manitoba	114	112
Northwest Territories	85	18
Wyoming	11	7
Total	2,842	1,957

We currently have no material work commitments on these lands. The primary lease or extension term on approximately 130,000 net acres of unproved property is scheduled to expire by December 31, 2014. The right to explore, develop and exploit these leases will be surrendered unless we qualify them for continuation based on production, drilling or technical mapping.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

The development of properties with no attributed reserves can be affected by a number of factors including, but not limited to, project economics, forecasted price assumptions, cost estimates, well type expectations and access to infrastructure. These and other factors could lead to the delay or the acceleration of projects related to these properties.

Tax Horizon

The most important variables that will determine the level of cash taxes incurred by us in a given year will be the price of crude oil and natural gas, our capital spending levels, the nature and extent of acquisition and disposition activities and the amount of tax pools available to us. We currently estimate that we will not be required to pay income taxes for the foreseeable future. However, if crude oil and natural gas prices were to strengthen beyond the levels anticipated by the current forward market, our tax pools would be utilized more quickly and we may experience higher than expected cash taxes or payment of such taxes in an earlier time period. However, we emphasize that it is difficult to give guidance on future taxability as we operate within an industry where various factors constantly change our outlook, including factors such as acquisitions, divestments, capital spending levels, operating cost levels and commodity price changes.

Capital Expenditures

The following table summarizes capital expenditures related to our activities for the year ended December 31, 2013, irrespective of whether such costs were capitalized or charged to expense when incurred.

	2013 MM$
Property Acquisition Costs[(1)]	
Proved Properties	(540)
Unproved Properties	4
Exploration Costs[(1)]	91
Development Costs[(1)]	682
Corporate Costs	10
Joint venture, carried capital	(83)
Total Capital Expenditures	164
Corporate Acquisitions	-
Total Expenditures	164

Note:

(1) "Property Acquisition Costs", "Proved Properties", "Unproved Properties", "Exploration Costs" and "Development Costs" have the meanings ascribed thereto in the COGE Handbook.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells that we participated in during the year ended December 31, 2013.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	2	2	272	200
Natural Gas	5	3	1	1
Service	1	-	13	2
Stratigraphic test	20	11	7	4
Dry	-	-	1	1
Total	28	16	294	208

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2014 which is reflected in the estimates of gross proved reserves and gross probable reserves disclosed in the tables contained under "Disclosure of Reserves Data" above.

	Light and Medium Oil (bbl/d)		Heavy Oil and Bitumen (bbl/d)		Natural Gas (Mcf/d)		Natural Gas Liquids (bbl/d)		Total Oil Equivalent (boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Developed Producing	44,092	37,445	12,869	11,220	212,608	193,431	7,574	5,624	101,469	86,528
Proved Developed Non-Producing	1,466	1,245	76	66	3,979	3,311	124	93	2,330	1,956
Proved Undeveloped	7,831	7,232	893	826	18,847	16,534	810	719	12,675	11,532
Total Proved	53,389	45,921	13,838	12,113	244,434	213,275	8,508	6,437	116,474	100,017
Total Probable	3,010	2,516	531	457	12,370	10,733	501	415	6,104	5,177
Total Proved Plus Probable	56,399	48,437	14,369	12,570	256,804	224,008	9,009	6,852	122,578	105,194

No one field (being a defined geographical area consisting of one or more pools) accounts for more than nine percent of the estimated production on a proved plus probable basis disclosed above. For more information, see "Other Oil and Gas Information – Description of Our Properties, Operations and Activities in Our Major Operating Regions".

Production History

The following table summarizes certain information in respect of our share of average gross daily production volumes, average net product prices received, royalties paid, production costs, transportation costs, risk management contracts loss (gain), and resulting netbacks for the periods indicated below:

	Quarter Ended 2013				Year Ended December 31, 2013
	March 31	June 30	September 30	December 31	
Share of Average Gross Daily Production					
Light and Medium Crude Oil (bbl/d)	63,366	62,676	58,792	54,852	59,895
Heavy Oil (bbl/d)	16,324	15,653	15,483	14,601	15,511
Gas (MMcf/d)	321	312	296	275	300
NGLs (bbl/d)	9,559	9,817	10,185	9,420	9,746
Combined (boe/d)	142,804	140,083	133,712	124,752	135,284
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	84.01	88.16	99.62	81.50	88.38
Heavy Oil ($/bbl)	50.78	67.10	84.02	58.66	65.12
Gas ($/Mcf)	3.18	3.70	2.83	3.51	3.30
NGLs ($/bbl)	55.16	47.46	50.86	53.76	51.75
Combined ($/boe)	53.93	58.49	63.67	54.49	57.67
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	12.29	13.10	15.29	14.49	13.75
Heavy Oil ($/bbl)	7.66	8.48	13.10	9.48	9.67
Gas ($/Mcf)	0.33	0.63	0.35	(0.14)	0.30
NGLs ($/bbl)	3.53	2.41	4.78	9.20	4.96
Combined ($/boe)	7.35	8.38	9.37	7.88	8.23
Production Costs(1)(2)					
Light and Medium Crude Oil ($/bbl)	23.78	26.12	24.87	30.39	26.19
Heavy Oil ($/bbl)	30.24	27.57	26.24	25.45	27.43
Gas ($/Mcf)	3.17	2.87	2.49	2.26	2.71
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	21.12	21.15	19.48	21.32	20.77
Transportation					
Light and Medium Crude Oil ($/bbl)	-	-	-	-	-
Heavy Oil ($/bbl)	0.03	0.05	0.09	0.07	0.06
Gas ($/Mcf)	0.26	0.26	0.26	0.27	0.26
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	0.59	0.59	0.58	0.61	0.59
Risk Management Contracts Loss (Gain)					
Light and Medium Crude Oil ($/bbl)	(0.59)	(0.32)	2.95	(0.52)	0.37
Heavy Oil ($/bbl)	-	-	-	-	-
Gas ($/Mcf)	(0.15)	0.10	(0.36)	(0.18)	(0.14)
NGLs ($/bbl)	-	-	-	-	-
Combined ($/boe)	(0.60)	0.07	0.50	(0.62)	(0.16)
Netback Received(3)					
Light and Medium Crude Oil ($/bbl)	48.53	49.26	56.50	37.13	48.06
Heavy Oil ($/bbl)	12.85	30.99	44.58	23.66	27.96
Gas ($/Mcf)	(0.43)	(0.16)	0.10	1.29	0.17
NGLs ($/bbl)	51.62	45.05	46.08	44.56	46.79
Combined ($/boe)	25.47	28.30	33.73	25.30	28.24

Notes:

(1) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, natural gas and natural gas liquids production.

(2) Operating overhead recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.
(3) Netbacks are calculated by subtracting royalties, operating costs, transportation costs and losses/gains on commodity and foreign exchange contracts from revenues.

During the year ended December 31, 2013, Penn West produced 49 MMboe, comprised of 22 MMbbl of light and medium oil, 6 MMbbl of heavy oil, 109 Bcf of natural gas and 4 MMbbl of natural gas liquids.

Marketing Arrangements

Our marketing approach incorporates the following primary objectives:

- Ensure security of market and avoid production shut-ins due to marketing constraints by dealing with end-users or regionally strategic counterparties wherever possible.

- Ensure competitive pricing by managing pricing exposures through a portfolio of various terms and geographic basis.

- Ensure optimization of netbacks through careful management of transportation obligations, facility utilization levels, blending opportunities and emulsion handling.

- Ensure protection of our receivables by, whenever possible, dealing only with credit worthy counterparties who have been subjected to regular credit reviews.

Oil and Liquids Marketing

Of our liquids production in 2013, approximately 70 percent was light and medium oil, 18 percent was conventional heavy oil and 12 percent was NGLs. In regard specifically to crude oil, our average quality was 33 degrees API, which was comprised of an average quality for our light and medium oil of 37 degrees API and an average quality for our conventional heavy oil of 12 degrees API.

To reduce risk, we market the majority of our production to large credit-worthy counterparties or end-users on varying term contracts and actively manage our heavy oil supply by finding opportunities to optimize netbacks through blending and trucking. Blending costs are also controlled through the use of proprietary condensate supply.

The following table summarizes the net product price received for our production of conventional light and medium oil (including NGLs) and our conventional heavy oil, before adjustments for hedging activities, for the periods indicated:

	2013		**2012**		**2011**	
Quarter Ended	**Light and Medium Oil and NGLs ($/bbl)**	**Heavy Oil ($/bbl)**	**Light and Medium Oil and NGLs ($/bbl)**	**Heavy Oil ($/bbl)**	**Light and Medium Oil and NGLs ($/bbl)**	**Heavy Oil ($/bbl)**
March 31	80.23	50.78	84.16	72.68	79.76	62.79
June 30	82.65	67.10	75.20	61.36	94.29	72.81
September 30	92.42	84.02	73.28	60.30	82.23	63.38
December 31	77.43	58.66	75.91	59.85	88.76	76.88

Natural Gas Marketing

In 2013, we received an average price from the sale of natural gas, before adjustments for hedging activities, of $3.30/Mcf, compared to $2.45/Mcf realized in 2012. Approximately 98 percent of our natural gas sales are marketed directly, with the balance of natural gas sales marketed in aggregator pools. We continue to maintain a significant weighting to the Alberta market which is one of the largest and most liquid market hubs in North America. In addition to maximizing netbacks, the current portfolio approach also enhances our flexibility to pursue higher netback opportunities as they become available.

We continue to conservatively manage our transportation costs. Transportation on all pipelines is closely balanced to supply, and market commitments related to export transportation represented approximately 17 percent of sales.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. In accordance with policies approved by our Board of Directors, we may, from time to time, manage these risks through the use of swaps, collars or other financial instruments. Commodity price risk may be hedged up to a maximum of 50 percent of forecast sales volumes, net of royalties, for the balance of any current year and one year following and up to 25 percent of forecast sales volumes, net of royalties, for one additional year thereafter. Subject to the Board's approval, our hedging limits may be increased above the maximum limits. This policy is reviewed by management and our Board of Directors from time to time and amended as necessary.

We are also exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our hedging portfolio among a number of counterparties, primarily parties within our banking syndicate, whom we consider to be financially sound.

As at December 31, 2013, we were not bound by any agreement (including a transportation agreement), directly or through an aggregator, under which we may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or natural gas, except for agreements disclosed by us in Note 12 to our restated audited consolidated financial statements as at and for the year ended December 31, 2013, which have been filed on SEDAR at www.sedar.com.

Our transportation obligations and commitments for future physical deliveries of crude oil and natural gas do not exceed our expected related future production from our proved reserves, estimated using forecast prices and costs, as disclosed herein.

APPENDIX B

MANDATE OF THE AUDIT COMMITTEE

1. PURPOSE

The purpose of the Audit Committee (the "Committee") of the board of directors (the "Board") of Penn West Petroleum Ltd. ("Penn West" or the "Company") is to assist the Board in fulfilling its responsibility for oversight of the integrity of Penn West's consolidated financial statements, Penn West's compliance with legal and regulatory requirements, the qualifications and independence of Penn West's independent auditors, and the performance of Penn West's internal audit function, if any.

The objectives of the Committee are as follows:

(a) To assist the Board in meeting its responsibilities (especially for accountability) in respect of the preparation and disclosure of the consolidated financial statements of Penn West and related matters;

(b) To provide better communication between directors and independent auditors;

(c) To assist the Board in meeting its responsibilities regarding the oversight of the independent auditor's qualifications and independence;

(d) To assist the Board in meeting its responsibilities regarding the oversight of the credibility, integrity and objectivity of financial reports;

(e) To strengthen the role of the non-management directors by facilitating discussions between directors on the Committee, management and independent auditors;

(f) To assist the Board in meeting its responsibilities regarding the oversight of the performance of Penn West's independent auditors and internal audit function (if any); and

(g) To assist the Board in meeting its responsibilities regarding the oversight of Penn West's compliance with legal and regulatory requirements.

2. SPECIFIC DUTIES AND RESPONSIBILITIES

Subject to the powers and duties of the Board, the Committee will perform the following duties:

(a) Satisfy itself on behalf of the Board that Penn West's internal control systems are sufficient to reasonably ensure that:

  (i) controllable, material business risks are identified, monitored and mitigated where it is determined cost effective to do so;

  (ii) internal controls over financial reporting are sufficient to meet the requirements under National Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings* and the *United States Securities Exchange Act of 1934*, as amended, and

  (iii) there is compliance with legal, ethical and regulatory requirements.

(b) Review the annual and interim financial statements of Penn West prior to their submission to the Board for approval. The process should include, but not be limited to:

  (i) review of changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

  (ii) review of significant accruals, reserves or other estimates such as the ceiling test calculation;

  (iii) review of accounting treatment of unusual or non-recurring transactions;

  (iv) review of compliance with covenants under loan agreements;

  (v) review of asset retirement obligations recommended by the Health, Safety, Environment and Regulatory Committee;

(vi) review of disclosure requirements for commitments and contingencies;

(vii) review of adjustments raised by the independent auditors, whether or not included in the financial statements;

(viii) review of unresolved differences between management and the independent auditors, if any;

(ix) review of reasonable explanations of significant variances with comparative reporting periods; and

(x) determination through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed.

(c) Review, discuss and recommend for approval by the Board the annual and interim financial statements and related information included in prospectuses, management discussion and analysis, information circular-proxy statements and annual information forms, prior to recommending Board approval.

(d) Discuss Penn West's interim results press releases, as well as financial information and earnings guidance provided to analysts and rating agencies (provided that the Committee is not required to review and discuss investor presentations that do not contain financial information or earnings guidance that has not previously been generally disclosed to the public).

(e) With respect to the appointment of independent auditors by the Board, the Committee shall:

(i) on an annual basis, review and discuss with the auditors all relationships the auditors have with Penn West to determine the auditors' independence, ensure the rotation of partners on the audit engagement team in accordance with applicable law and, in order to ensure continuing auditor independence, consider the rotation of the audit firm itself;

(ii) be directly responsible for overseeing the work of the independent auditors engaged for the purpose of issuing an auditors' report or performing other audit, review or attest services for Penn West, including the resolution of disagreements between management and the independent auditor regarding financial reporting, and the independent auditors shall report directly to the Committee;

(iii) review and evaluate the performance of the lead partner of the independent auditors;

(iv) review the basis of management's recommendation for the appointment of independent auditors and recommend to the Board appointment of independent auditors and their compensation;

(v) review the terms of engagement and the overall audit plan (including the materiality levels to be applied) of the independent auditors, including the appropriateness and reasonableness of the auditors' fees;

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

(vii) review and pre-approve any audit and permitted non-audit services to be provided by the independent auditors' firm and consider the impact on the independence of the auditors.

(f) The Committee may delegate to one or more members of the Committee authority to pre-approve non-audit services in satisfaction of 2(e) (vii) above and if such delegation occurs, the pre-approval of non-audit services by the Committee member to whom authority has been delegated must be presented to the Committee at its first scheduled meeting following such pre-approval. The Committee shall be entitled to adopt specific policies and procedures for the engagement of non-audit services if:

(i) the pre-approval policies and procedures are detailed as to the particular service;

(ii) the Committee is informed of each non-audit service so approved; and

(iii) the procedures do not include delegation of the Committee's responsibilities to management;

provided that in order for the pre-approval requirements to be satisfied for any non-audit services that are not pre-approved in accordance with the procedures set forth above:

(iv) the aggregate amount of all non-audit services that were not pre-approved (if any) must be reasonably expected to constitute no more than 5% of the total amount of fees paid by Penn West and its subsidiary entities to the auditors during the fiscal year in which the services are provided;

(v) Penn West or the subsidiary entity, as the case may be, must not have recognized the services as non-audit services at the time of the engagement; and

(vi) the services must have been promptly brought to the attention of the Committee and approved, prior to completion of the audit, by the Committee or by one or more of its members to whom authority to grant such approvals has been delegated by the Committee.

(g) At least annually, obtain and review the report by the independent auditors describing the independent auditors' internal quality control procedures, any material issues raised by the most recent interim quality-control review, or peer review, of the independent auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the independent auditors, and any steps taken to deal with any such issues.

(h) Review with the independent auditors (and internal auditors, if any) their assessment of the internal controls of the Company, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the independent auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Penn West and its subsidiaries.

(i) At least annually, obtain and review a report by the independent auditors describing (i) all critical accounting policies and practices used by Penn West, (ii) all alternative accounting treatments of financial information within generally accepted accounting principles related to material items that have been discussed with management, including the ramifications of the use of such alternative treatments and disclosures and the treatment preferred by the accounting firm, and (iii) other material written communications between the accounting firm and management of Penn West.

(j) Obtain assurance from the independent auditors that disclosure to the Committee is not required pursuant to the provisions of the *United States Securities Exchange Act of 1934*, as amended, regarding the discovery by the independent auditors of illegal acts.

(k) Review, set and approve hiring policies relating to current and former staff of current and former independent auditors.

(l) Review all public disclosure containing financial information before release (provided that the Committee is not required to review investor presentations that do not contain financial information or earnings guidance that has not previously been generally disclosed to the public).

(m) Review all pending significant litigation to ensure disclosures are sufficient and appropriate.

(n) Satisfy itself that adequate procedures are in place for the review of Penn West's public disclosure of financial information from Penn West's financial statements and periodically assess the adequacy of those procedures.

(o) Review and discuss major financial risk exposures and the steps management has taken to monitor and control such exposures.

(p) Establish procedures independent of management for:

(i) the receipt, retention and treatment of complaints received by Penn West regarding accounting, internal accounting controls, or auditing matters; and

(ii) the confidential, anonymous submission by employees of Penn West of concerns regarding questionable accounting or auditing matters.

(q) Review any other matters required by law, regulation or stock exchange requirement, or that the Committee feels are important to its mandate or that the Board chooses to delegate to it.

(r) Establish, review and update periodically a Code of Business Conduct and Ethics and a Code of Conduct for Senior Officers and Senior Financial Management and ensure that management has established systems to enforce these codes.

(s) Review management's monitoring of Penn West's compliance with the organization's Code of Business Conduct and Ethics and Code of Conduct for Senior Officers and Senior Financial Management.

(t) Review and discuss with the Chief Executive Officer, the Chief Financial Officer and the independent auditors, the matters required to be reviewed with those persons in connection with any certificates required by applicable laws, regulations or stock exchange requirements to be provided by the Chief Executive Officer and the Chief Financial Officer.

(u) Review and discuss major issues regarding accounting principles and financial statement presentations, including any significant changes in Penn West's selection or application of accounting principles.

(v) Review and discuss major issues as to the adequacy of Penn West's internal controls and any special audit steps adopted in light of material control deficiencies.

(w) Review and discuss analyses prepared by management and/or the independent auditors setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative generally accepted accounting principles methods on the financial statements.

(x) Review and discuss the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on Penn West's financial statements.

(y) Review and discuss the type and presentation of information to be included in earnings press releases, paying particular attention to any use of "pro forma" or "adjusted" non-GAAP information.

(z) annually review the Committee's Mandate and the Committee Chair's Terms of Reference and recommend any proposed changes to the Board for consideration; and

(aa) review and approve any other matters specifically delegated to the Committee by the Board.

3. KNOWLEDGE & EDUCATION

Committee members shall be "financially literate" within the meaning of NI 52-110, and should have or obtain sufficient knowledge of Penn West's financial and audit policies and procedures to assist in providing advice and counsel on related matters. Members shall be encouraged as appropriate to attend relevant educational opportunities at the expense of Penn West.

4. COMPOSITION

(a) The Committee shall be composed of at least three members of the Board or such greater number as the Board may from time to time determine.

(b) Committee members shall be appointed and removed by the Board.

(c) Each member of the Committee shall be an "independent" director in accordance with the definition of "independent" in (a) National Instrument 52-110 *Audit Committees* ("NI 52-110") and (b) Section 303A.02 and 303A.07 of the New York Stock Exchange Listed Company Manual, and in accordance with all other applicable securities laws or rules of any stock exchange on which Penn West's securities are listed for trading.

(d) All of the members must be "financially literate" within the meaning of NI 52-110 and Section 303A.07 (a) of the New York Stock Exchange Listed Company Manual unless the Board has determined to rely on an exemption in NI 52-110. Being "financially literate" means members have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by Penn West's financial statements. In addition, at least one member of the Committee must have accounting or related financial management expertise, as the Board interprets such qualification in its business judgment.

(e) In connection with the appointment of the members of the Committee, the Board will determine whether any proposed nominee for the Committee serves on the audit committees of more than three public companies. To the extent that any proposed nominee for membership on the Committee serves on the audit committees of more than three public companies, the Board will make a determination as to whether such simultaneous services would impair the ability of such member to effectively serve on the Company's Audit Committee and will disclose such determination in Penn West's annual proxy information circular and annual report on Form 40-F filed with the United States Securities and Exchange Commission.

5. MEETINGS

(a) The Committee shall meet at least four times per year at the call of the Committee Chair. The Committee Chair may call additional meetings as required. In addition, a meeting may be called by the Chairman of the Board, the Chief Executive Officer, the Chief Financial Officer, the Chief Operating Officer or any member of the Committee.

(b) As part of its job to foster open communication, the Committee should meet at least annually with management, internal auditors (if any) and the independent auditors in separate executive sessions to discuss any matters that the Committee or each of these groups believe should be discussed privately. In addition, the Committee shall meet with the independent auditors and management quarterly to review Penn West's interim financials. The Committee shall also meet with management and independent auditors on an annual basis to review and discuss Penn West's annual financial statements and the management's discussion and analysis of financial conditions and results of operations.

(c) Notice of the time and place of every meeting may be given orally, in writing, by facsimile or by other electronic means of communication to each member of the Committee at least 48 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.

(d) A quorum shall be a majority of the members of the Committee.

(e) Committee meetings may be held in person, by video conference, by teleconference or by combination of any of the foregoing.

(f) As part of each Committee meeting the Committee members will also meet "in-camera" without any members of management present.

(g) The Committee Chair shall be a full voting member of the Committee.

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

(i) The Chair of any Committee meeting (including, without limitation, any Chair selected in accordance with paragraph (h) above)) shall have a casting vote in the event of a tie on any matter upon which the Committee votes during such meeting.

(j) 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. However, independent directors, including the Chairman of the Board, shall always have the right to be present.

(k) Agendas, with input from management and the Committee Chair, shall be circulated by the Committee Secretary to Committee members and relevant members of management along with appropriate meeting materials and background reading on a timely basis prior to Committee meetings.

6. MINUTES

(a) The secretary to the Committee (the "Committee Secretary") will be either the Corporate Secretary of the Company or his/her delegate. The Committee Secretary shall record and maintain minutes of the meetings of the Committee.

(b) Minutes of Committee meetings shall be approved by the Committee and maintained with Penn West's records by the Committee Secretary or designate.

7. REPORTING / AUTHORITY

(a) At the first Board meeting following a Committee meeting, the Committee will provide a verbal report to the Board of the material matters discussed and material resolutions passed at the Committee meeting. The draft minutes of the Committee meeting will subsequently be provided to all Board members as soon as practicable.

(b) Supporting schedules and information reviewed by the Committee shall be available for examination by any member of the Board.

(c) The Committee shall have the authority to investigate any financial activity of Penn West and to communicate directly with the internal auditors (if any) and independent auditors. All employees are to cooperate as requested by the Committee.

(d) The Committee may retain, and set and pay the compensation for, persons having special expertise and/or obtain independent professional advice, including the engagement of independent counsel and other advisors, to assist in fulfilling its duties and responsibilities at the expense of Penn West.

(e) The Committee may delegate any of its duties and responsibilities hereunder to the Committee Chair or any group of members of the Committee.

(f) The Committee, in its capacity as a committee of the Board, shall determine appropriate funding and cause such funding to be available (i) to Penn West's independent auditors for the purpose of preparing and issuing an audit report, (ii) to any advisors employed by the Committee, and (iii) for ordinary administration expenses of the Committee that are necessary or appropriate in carrying out its duties.

8. ACCOUNTABILITY

The Committee's performance shall be evaluated by the Board as part of the Board assessment process established by the Governance Committee and the Board.

9. RESOURCES

(a) The Committee may retain special legal, accounting, financial or other consultants or advisors to advise the Committee at Penn West's expense and shall have sole authority to retain and terminate any such consultants or advisors and to approve any such consultant's or advisor's fees and retention terms, subject to review by the Board.

(b) The Committee shall have access to Penn West's senior management and documents as required to fulfill its responsibilities and shall be provided with the resources necessary to carry out its responsibilities.

(c) The Chief Executive Officer and the Chief Financial Officer, or their designates, shall be available to attend meetings of the Committee.

(d) Such other staff as appropriate to provide information to the Committee shall attend meetings upon invitation by the Committee, the Chief Executive Officer or the Chief Financial Officer.

(e) The Committee may, by specific invitation, have other resource persons in attendance to assist in the discussion and consideration of matters relating to the Committee.

10. DELEGATION

The Committee may delegate from to time to any person or committee of persons any of the Audit Committee's responsibilities that are permitted to be delegated to such person or committee in accordance with applicable laws, regulations and stock exchange requirements.

11. STANDARDS OF LIABILITY

(a) Nothing contained in this Mandate is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this Mandate are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities, subject to applicable statutory, regulatory and other legal requirements.

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