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

FORM 40-F

(Check One)

¨ **Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934**

or

x **Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2012

Commission file number 1-32895

PENN WEST PETROLEUM LTD.

(Exact name of registrant as specified in its charter)

Alberta, Canada	**1311**	**Not applicable**
(Province or other jurisdiction of incorporation or organization)	**(Primary Standard Industrial Classification Code Number (if applicable))**	**(I.R.S. Employer Identification Number (if Applicable))**

Suite 200, 207 – 9th Avenue SW, Calgary, Alberta, Canada T2P 1K3
(403) 777-2500
(Address and Telephone Number of Registrant's Principal Executive Offices)

DL Services Inc., Columbia Center, 701 Fifth Avenue, Suite 6100, Seattle, Washington 98104-7043
(206) 903-5448
(Name, Address (Including Zip Code) and Telephone Number (Including Area Code) of Agent For Service in the United States)

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

Title of each class	**Name of each exchange on which registered**
Common Shares	**New York Stock Exchange**

Securities registered or to be registered pursuant to Section 12(g) of the Act: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

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

x **Annual Information Form** x **Audited Annual Financial Statements**

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: **479,258,670**

Indicate by check mark whether Penn West: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that Penn West was required to file such reports); and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). Yes ¨ No ¨

Principal Documents

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

(a) Annual Information Form for the fiscal year ended December 31, 2012;

(b) Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2012; and

(c) Audited Consolidated Financial Statements for the fiscal year ended December 31, 2012, prepared under International Financial Reporting Standards as issued by the International Accounting Standards Board.

(d) Supplemental Oil and Gas information

ADDITIONAL DISCLOSURE

Certifications and Disclosure Regarding Controls and Procedures.

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

(b) Disclosure Controls and Procedures. As of the end of Penn West Petroleum Ltd.'s ("Penn West") fiscal year ended December 31, 2012, an evaluation of the effectiveness of Penn West's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) was carried out by the management of Penn West, with the participation of the President & Chief Executive Officer ("CEO") and the Executive Vice President and Chief Financial Officer ("CFO") of Penn West. Based upon that evaluation, the CEO and CFO have concluded that as of the end of that fiscal year, Penn West's disclosure controls and procedures were effective to ensure that information required to be disclosed by Penn West in reports that it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission (the "Commission") rules and forms and (ii) accumulated and communicated to the management of Penn West, including the CEO and CFO, to allow timely decisions regarding required disclosure.

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

(c) Management's Annual Report on Internal Control Over Financial Reporting.

Management is responsible for establishing and maintaining adequate internal control over Penn West's financial reporting. Penn West's internal control system was designed to provide reasonable assurance that all transactions are accurately recorded, that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that Penn West's assets are safeguarded.

Management has assessed the effectiveness of Penn West's internal control over financial reporting as at December 31, 2012. In making its assessment, management used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework to evaluate the effectiveness of Penn West's internal control over financial reporting. Based on this assessment, management has concluded that Penn West's internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of Penn West's internal control over financial reporting as at December 31, 2012 has been audited by KPMG LLP, as stated in their Report of Independent Registered Public Accounting Firm on Penn West's internal control over financial reporting that accompanies Penn West's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2012, filed as Exhibit 99.3 to this Annual Report on Form 40-F.

(d) Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the Report of Independent Registered Public Accounting Firm on Penn West's internal control over financial reporting that accompanies Penn West's Audited Consolidated Financial Statements for the fiscal year ended December 31, 2012, filed as Exhibit 99.3 to this Annual Report on Form 40-F.

(e) Changes in Internal Control Over Financial Reporting. There were no changes in Penn West's internal control over financial reporting that occurred during the fiscal year ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, Penn West's internal control over financial reporting.

Notices Pursuant to Regulation BTR.

None.

Audit Committee Financial Expert.

Penn West's board of directors has determined that James C. Smith, a member of Penn West's audit committee, qualifies as an "audit committee financial expert" (as such term is defined in Form 40-F). Mr. Smith is "independent" as that term is defined in the rules of the New York Stock Exchange.

Code of Business Conduct.

Penn West has adopted a Code of Ethics for Officers and Senior Financial Management. Penn West has also adopted a Code of Business Conduct and Ethics that applies to all employees, officers and directors of Penn West. Together, these Codes constitute a "code of ethics" as defined in Form 40-F and are collectively referred to in this Annual Report on Form 40-F as the "Code of Ethics".

The Code of Ethics, including each of its components, is available for viewing on Penn West's website at www.pennwest.com, and is available in print to any shareholder who requests a copy. Requests for copies of the Code of Ethics or any portion of it should be made by contacting: investor relations by phone at (888) 770-2633 or by e-mail to investor_relations@pennwest.com.

Since the adoption of each component of the Code of Ethics, there have not been any amendments to, or waivers, including implicit waivers, from, any provision of such Codes.

If any amendment to the Code of Ethics is made, or if any waiver from the provisions thereof is granted, Penn West may elect to disclose the information about such amendment or waiver required by Form 40-F to be disclosed, by posting such disclosure on Penn West's website, which may be accessed at www.pennwest.com.

Principal Accountant Fees and Services.

The following table sets forth information about the fees billed to Penn West for professional services provided by KPMG LLP during fiscal 2012 and 2011:

(CDN$)	**2012**	**2011**
Audit Fees	1,120,000	1,230,000
Audit-Related Fees	146,000	157,500
Tax Fees	38,000	—
Total	1,304,000	1,387,500

Audit Fees. Audit fees consist of 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.

Audit-Related Fees. Audit-related fees primarily consist of assurance and related services for the Peace River Oil Partnership audit and for French translation services.

Tax fees. Tax fees consist of professional services for tax compliance, tax advice and tax planning.

Pre-Approval Policies and Procedures.

(a) 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 disclaimers 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 shall 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 at the audit committee's first scheduled meeting following such pre-approval.

(b) Of the fees reported in this Annual Report on Form 40-F under the heading "Principal Accountant Fees and Services", none of the fees billed by KPMG LLP were approved by Penn West's audit committee pursuant to the *de minimus* exception provided by Section (c)(7)(i)(C) of Rule 2-01 of Regulation S-X.

Off-Balance Sheet Arrangements.

Penn West has off-balance-sheet financing arrangements consisting of operating leases. The operating lease payments are summarized below in the Tabular Disclosure of Contractual Obligations.

Tabular Disclosure of Contractual Obligations.

(CDN$ millions)

Contractual Obligations	Total	Payment due by period: Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
Transportation	56	24	27	5	—
Transportation ($US)	342	4	74	66	198
Power infrastructure	97	29	28	28	12
Drilling rigs	78	23	38	17	—
Purchase obligations (1)	19	6	10	2	1
Office lease (2)	663	62	111	106	384
Long-term debt (3)(4)	2,690	5	311	1,210	1,164
Decommissioning liability (5)	3,201	107	214	214	2,666
Total	**7,146**	**260**	**813**	**1,648**	**4,425**

(1) These amounts represent estimated commitments of $13 million for CO2 purchases and $6 million for processing fees related to interests in the Weyburn Unit.
(2) Future office lease commitments will be reduced by sublease recoveries of $335 million.
(3) Penn West's syndicated bank facility is due for renewal on June 30, 2016. Penn West and its predecessor have successfully extended its credit facility on each renewal date since 1992.
(4) Interest payments have not been included since future debt levels and rates are not known at this time.
(5) These amounts represent the undiscounted future reclamation and abandonment costs that are expected to be incurred over the life of the properties.

Identification of the Audit Committee.

Penn West has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: James C. Smith, James E. Allard, Gillian H. Denham, George H. Brookman and Frank Potter.

Mine Safety Disclosure.

Not applicable.

Disclosure Pursuant to the Requirements of the New York Stock Exchange.

Presiding Director at Meetings of Non-Management Directors

Penn West schedules regular executive sessions in which Penn West's "non-management directors" (as that term is defined in the rules of the New York Stock Exchange) meet without management participation. John A. Brussa, the Chairman of the board of directors, serves as the presiding director (the "Presiding Director") at such sessions. Penn West's board of directors is responsible for determining whether or not each director is independent. In making this determination, the board of directors has adopted the definition of "independence" as set out in Section 1.4 of Multilateral Instrument 52-110 Audit Committees ("MI 52-110"). In applying this definition, the board of directors considers all relationships of the directors with Penn West, including business, family and other relationships. Penn West's board of directors also determines whether each member of Penn West's audit committee is independent pursuant to Sections 1.4 and 1.5 of MI 52-110 and Rule 10A-3 under the Exchange Act. Penn West's board of directors has not adopted the director independence standards contained in Section 303A.02 of the NYSE's Listed Company Manual.

Communication with Non-Management Directors

Shareholders may send communications to Penn West's non-management directors by writing to George H. Brookman, Chairman of the governance committee of the board of directors, care of Investor Relations, Penn West Petroleum Ltd., 200, 207 – 9th Avenue SW, Calgary, Alberta, T2P 1K3 Canada. Communications will be referred to the Presiding Director for appropriate action. The status of all outstanding concerns addressed to the Presiding Director will be reported to the board of directors as appropriate.

Corporate Governance Guidelines

In accordance with the rules of the New York Stock Exchange, Penn West has adopted corporate governance guidelines, entitled "Governance Guidelines", which are available for viewing on Penn West's website at www.pennwest.com and are available in print to any shareholder who requests a copy of them. Requests for copies of the Governance Guidelines should be made by contacting: investor relations by phone (888) 770-2633 or by e-mail to investor_relations@pennwest.com.

Board Committee Mandates

The Mandates of Penn West's audit committee, human resources and compensation committee, governance committee, reserves and A&D committee and health, safety and environment committee are each available for viewing on Penn West's website at www.pennwest.com, and are available in print to any shareholder who requests them. Requests for copies of these documents should be made by contacting: investor relations by phone (888) 770-2633 or by e-mail to investor_relations@pennwest.com.

NYSE Statement of Governance Differences

As a Canadian corporation listed on the NYSE, Penn West is not required to comply with most of the NYSE corporate governance standards, so long as it complies with Canadian corporate governance practices. In order to claim such an exemption, however, Penn West must disclose the significant difference between its corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE's corporate governance standards. Penn West has included a description of such significant differences in corporate governance practices on its website which may be accessed at www.pennwest.com.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking.

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

B. Consent to Service of Process.

Penn West has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

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

SIGNATURES

Pursuant to the requirements of the Exchange Act, Penn West Petroleum Ltd. certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized, on March 14, 2013.

Penn West Petroleum Ltd.

By: /s/ Murray R. Nunns
Name: Murray R. Nunns
Title: President & Chief Executive Officer

EXHIBIT INDEX

Exhibit	Description
99.1	Annual Information Form for the fiscal year ended December 31, 2012
99.2	Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2012
99.3	Consolidated Financial Statements for the fiscal year ended December 31, 2012
99.4	Supplemental Oil and Gas information
99.5	Certification of President & Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.6	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14 of the Securities Exchange Act of 1934
99.7	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
99.8	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
99.9	Consent of KPMG LLP
99.10	Consent of GLJ Petroleum Consultants Ltd.
99.11	Consent of Sproule Associates Limited

Exhibit 99.1



PENN WEST PETROLEUM LTD.

Annual Information Form
for the year ended December 31, 2012

March 13, 2013

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APPENDIX A – RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Appendix A-1 – Report of Management and Directors on Reserves Data and Other Information
Appendix A-2 – Report on Reserves Data
Appendix A-3 – Statement of Reserves Data and Other Oil and Gas Information

APPENDIX B – MANDATE OF THE AUDIT COMMITTEE

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.

"**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 Reports**" means, collectively, the GLJ Report and the Sproule Report.

"**Form 40-F**" means our Annual Report on Form 40-F for the fiscal year ended December 31, 2012 filed with the SEC.

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

"**GLJ Report**" means the report prepared by GLJ dated January 31, 2013 evaluating approximately 48 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, 2012.

"**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 Handbook of the Canadian Institute of Chartered Accountants, as amended from time to time.

"**IFRS**" means international financial reporting standards, being the standards and interpretations adopted 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$1,634 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.

"**Sproule Report**" means the report prepared by Sproule dated February 22, 2013 evaluating approximately 30 percent and auditing approximately 22 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, 2012.

"**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.

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

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

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 13, 2013, the exchange rate based on the noon rate as reported by the Bank of Canada, was Cdn$1.00 equals US$0.9734.

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

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel or barrels
bbl/d	barrels per day
Mbbl	thousand barrels
MMbbl	million barrels
NGLs	natural gas liquids
MMboe	million barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day

Natural Gas

GJ	gigajoule
GJ/d	gigajoules per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres

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 Annual Report on Form 40-F for the year ended December 31, 2012 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

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", "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 2013 capital expenditure budget, including the anticipated amount to be allocated to light oil projects and the potential to increase the budget and the timing thereof; our ongoing acquisition, disposition, farm-out and financing strategy; the terms of our Senior Notes and unsecured revolving credit facility; 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; 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 belief that the various laws and regulations governing the oil and gas industry will not affect our operations in a manner materially different than other oil and gas companies of a similar size; our beliefs regarding the materiality of our financial obligations associated with non-operated facilities; our expectations regarding the operational and financial impact that climate change regulations in the jurisdictions in which we operate will have on us; anticipated thresholds that our facilities will achieve in relation to the Cap and Trade Act (as defined herein); our belief that our financial obligations associated with the reporting and verification requirements under the Cap and Trade Act are not material; 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 "Statement of Reserves Data and Other Oil and Gas Information – Reserves Data (Forecast Prices and Costs)"; 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 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 wells and facilities 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; our exploration and development plans for our oil and natural gas properties in 2013 and beyond, including key focus areas, drilling plans, pilot projects, plans to expand infrastructure, resource appraisal and assessment work, our anticipated 2013 capital expenditure levels in each of our key resource plays and the key elements of our 2013 capital expenditure program; our belief that recent 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 expectation regarding when we will be required to pay income taxes; our estimated capital expenditure levels in 2013; our production volume estimates for 2013; 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 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; future capital expenditure levels and capital programs; 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; future oil, natural gas liquids and natural gas prices and differentials between light, medium and heavy oil prices; future oil and natural gas production levels; 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; the cost of expanding our property holdings; 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; 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 “Statement of Reserves Data and Other Oil and Gas Information – Reserves Data (Forecast Prices and Costs)” and “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 impact of weather conditions (including wild fires and flooding) on seasonal demand and our ability to execute capital programs; 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 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; royalties payable in respect of our oil and natural gas production and changes thereto; changes in government regulation of the oil and natural gas industry, including environmental regulation; fluctuations in foreign exchange or interest rates; unanticipated operating events that can reduce production or cause production to be shut-in or delayed; failure to obtain industry partner and other third-party consents and approvals when required; 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; the need to obtain required approvals from regulatory authorities from time to time; failure to realize the anticipated benefits of dispositions, acquisitions, joint ventures and partnerships, including the historical dispositions, acquisitions, joint ventures and partnerships discussed herein; 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; changes in taxation and other laws and regulations that affect us and our securityholders; changes in government royalty frameworks in jurisdiction in which we operate and the impact that such changes may have on us; uncertainty of obtaining required approvals in respect of dispositions, acquisitions, joint ventures, partnerships and mergers; the potential failure of counterparties to honour their contractual obligations; 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.

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, 2012.

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 under the trade name “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

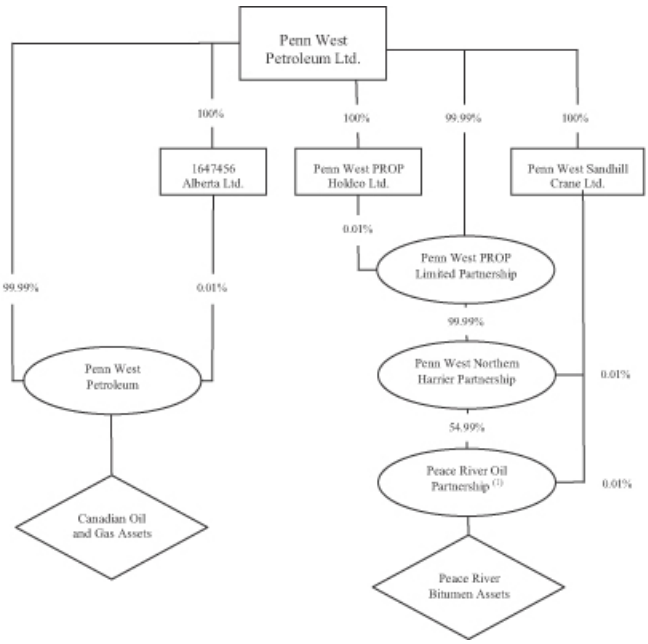
The Corporate Conversion was completed on January 1, 2011 and resulted in the reorganization of Penn West Trust (an income trust) into Penn West (a corporation) and the unitholders of Penn West Trust becoming the Shareholders of Penn West. Penn West and its Subsidiaries now carry on the business formerly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

We are a Canadian exploration and production company actively engaged in the business of acquiring, exploring, developing, exploiting and holding interests in petroleum and natural gas properties and related assets. We have historically focused on a balance of drilling on internally generated prospects and completing cost-effective acquisitions.

As at December 31, 2012, we had approximately 2,130 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, 2012.

General Development of the Business

The following is a description of the general development of our business over the last three completed financial years.

Year Ended December 31, 2010

Asset Exchange Agreement

On January 15, 2010, Penn West closed an asset exchange transaction (the " **Asset Exchange Transaction**") pursuant to which we increased our position in our light-oil resource plays in the Pembina and Dodsland areas. Penn West acquired production of approximately 560 boe per day and approximately 25,000 net acres of undeveloped land along with net cash proceeds of $434 million. In exchange, Penn West disposed of certain interests in the Leitchville area in Saskatchewan with approximately 3,500 boe per day of production. Funds received were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Private Placement of Notes

Effective March 16, 2010, Penn West completed the private placement of our Series Q, Series R, Series S, Series T, Series U and Series V Senior Notes, which consisted of the issuance of US$27.5 million principal amount of 4.53 percent notes due in 2015, US$65 million principal amount of 5.29 percent notes due in 2017, US$112.5 million principal amount of 5.85 percent notes due in 2020, US$25 million principal amount of 5.95 percent notes due in 2022, US$20 million principal amount of 6.10 percent notes due in 2025, and Cdn$50 million principal amount of 4.88 percent notes due in 2015. Each of these Series of Senior Notes is guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes. The proceeds of the private placement were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Renewal of Credit Facilities

On April 30, 2010, Penn West renewed its unsecured, revolving credit facility for a three-year term ending April 30, 2013 with a syndicate of Canadian and international banks. The credit facility had an aggregate borrowing limit of $2.25 billion.

Partnership and Equity Financing with Affiliate of China Investment Corporation

On June 1, 2010, Penn West closed the formation of the Peace River Oil Partnership (" **PROP**") with Winter Spark Resources, Inc. (the " **CIC Affiliate**"), an affiliate of China Investment Corporation. PROP was formed to develop Penn West's bitumen assets located in the Peace River area of northern Alberta (the "**Peace River Assets**"). The Peace River Assets included approximately 237,000 net acres of oil sands leases and production of approximately 2,700 boe/d of bitumen and associated gas. Penn West contributed the Peace River Assets (valued at approximately $1.8 billion) to PROP and retained a 55 percent interest in PROP. The CIC Affiliate acquired a 45 percent interest in PROP by investing approximately $312 million in PROP (which was subsequently paid to Penn West by PROP to satisfy outstanding indebtedness of PROP to Penn West) and by committing to carry a portion of Penn West's share of PROP's future capital and operating expenses aggregating approximately an additional $505 million. Penn West serves as operator of PROP. Penn West also issued 23,524,209 Trust Units to the CIC Affiliate at a price of approximately $18.48 per Trust Unit for gross proceeds of approximately $435 million. The approximately $747 million of proceeds received upon closing were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Joint Venture with Affiliate of Mitsubishi Corporation

On September 23, 2010, Penn West closed the formation of a joint venture (the " **Cordova JV**") with an affiliate of Mitsubishi Corporation (the "**Mitsubishi Affiliate**"). The Cordova JV was formed to develop certain of Penn West's shale gas assets and conventional natural gas assets located in northeastern British Columbia (the "**Cordova Assets**"). Penn West sold the Mitsubishi Affiliate a 50 percent working interest in the Cordova Assets, which consisted of production of approximately 30 mmcf/d (gross) of conventional natural gas, approximately 550,000 acres (gross) of land (including approximately 120,000 acres (gross) of land prospective for shale gas in the Cordova Embayment), the Wildboy gas processing facility, the sales gas pipeline connecting the area to the TransCanada gathering system in Alberta, and all associated infrastructure. The Mitsubishi Affiliate paid Penn West approximately $250 million for its 50 percent working interest in the Cordova Assets and committed to fund approximately $600 million of the first $800 million of the Cordova JV's initial exploration and development capital expenditures. Penn West retained a 50 percent working interest in the Cordova Assets and serves as operator of the assets. The approximately $250 million of proceeds from the transaction were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Aggregate Acquisition and Disposition Activity

Including the Asset Exchange Transaction, the PROP transaction and the Cordova JV described above, Penn West completed property dispositions, net of acquisitions, of approximately $1,306 million in 2010.

Private Placement of Notes

On December 2, 2010 and January 4, 2011, Penn West completed the private placement of our Series W, Series X, Series Y, Series Z, Series AA and Series BB Senior Notes, which consisted of the issuance of US$18 million principal amount of 4.17 percent notes due in 2017, US$84 million principal amount of 4.88 percent notes due in 2020, US$18 million principal amount of 4.98 percent notes due in 2022, US$50 million principal amount of 5.23 percent notes due in 2025, Cdn$10 million principal amount of 4.44 percent notes due in 2015, and Cdn$50 million principal amount of 5.38 percent notes due in 2020. Each of these Series of Senior Notes is guaranteed, unsecured and ranks equally with our bank credit facilities and our other Senior Notes. The proceeds of the private placement were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

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. Our 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, our 7.2% convertible, unsecured, subordinated debentures matured and were settled in cash for a total of approximately $24 million.

On December 31, 2011, our 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.

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 our 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 our bank credit facilities and our other Senior Notes. The proceeds of the private placement were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Aggregate Acquisition and Disposition Activity

Penn West completed 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 property dispositions, net of acquisitions, of approximately $1,615 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.

2013 Developments

2013 Capital Expenditure Budget

On January 9, 2013, Penn West announced a base capital expenditure budget for 2013 of $900 million (approximately 90% of which was anticipated to be allocated to light oil projects), with the potential to increase the budget by an additional $300 million weighted in the second half of 2013 (subject to certain conditions, prevailing circumstances and Board approval).

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. Penn West is normally in the process of evaluating several potential acquisitions 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 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 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 (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 as such).

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 13, 2013, 482,205,286 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$1,634 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$ 35 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 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$35 million principal amount of the Series M notes outstanding in seven installments on May 5 of each year beginning in 2013 and 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 13, 2013, approximately $1.1 billion had been borrowed under the credit facility.

Additional Information

For additional information regarding our Senior Notes and our credit facility, see Notes 9 and 19 (collectively, the " **Note Disclosure**") to our audited consolidated financial statements for the year ended December 31, 2012, and "Financing" and "Liquidity and Capital Resources" in our related management's discussion and analysis (collectively, the "**MD&A Disclosure**"), both of which are available on SEDAR at www.sedar.com. The Note Disclosure and the MD&A Disclosure are both incorporated by reference into this Annual Information Form.

Ratings

Penn West has not asked for and received a stability rating, and it is not aware that it has received any other kind of rating, including a provisional rating, from one or more approved rating organizations for outstanding securities of Penn West, which rating or ratings continue in effect.

DIRECTORS AND EXECUTIVE OFFICERS OF PENN WEST

The following table as of March 13, 2013 sets forth 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[1][2] Alberta, Canada	Director since June 30, 2006	Independent director and business advisor.
William E. Andrew Alberta, Canada	Vice Chairman Director since June 3, 1994	Chairman of Long Run Exploration Ltd. (and its predecessors) ("Long Run"), a public oil and natural gas company, since August 2011 and Chief Executive Officer of Long Run since November 2011. Prior thereto, Chief Executive Officer of Penn West from January 2008 to August 2011. Prior thereto, President and Chief Executive Officer of Penn West.
George H. Brookman[1][2][4] Alberta, Canada	Director since August 3, 2005	President and Chief Executive Officer of West Canadian Industries Group Inc. (a commercial digital printing and graphics company).
John A. Brussa Alberta, Canada	Chairman of the Board of Directors Director since April 21, 1995	Senior Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Gillian H. Denham[1][2][4] Ontario, Canada	Director since June 13, 2012	Corporate director.
Daryl H. Gilbert[3][5] Alberta, Canada	Director since January 11, 2008	Independent businessman since 2005 and Managing Director of JOG Capital Inc. (a private equity investment management company) since 2008.
Shirley A. McClellan[2][5] Alberta, Canada	Director since June 8, 2007	Chancellor of the University of Lethbridge since February 2011. Distinguished Scholar in Residence at the University of Alberta for the Faculties of Agriculture and Rural Economy and the School of Business since September 2007. Independent businesswoman since 2007.
Murray R. Nunns Alberta, Canada	President and Chief Executive Officer Director from May 27, 2005 to January 11, 2008 and director since June 9, 2009	President and Chief Executive Officer of Penn West since August 2011. Prior thereto, President and Chief Operating Officer of Penn West from February 2008 to August 2011. Prior thereto, director of Penn West and Executive Chairman of Monterey Exploration Ltd., a public oil and natural gas company.
Frank Potter[1][4] Ontario, Canada	Director since June 30, 2006	Independent director for a number of public, private and not-for-profit corporations.

Name, Province and Country of Residence	Positions and Offices Held with Penn West	Principal Occupations during the Five Preceding Years
Jack Schanck[3][4][5] Alberta, Canada	Director since June 2, 2008	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.
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. Prior thereto, Senior Vice President, Engineering of Penn West from January 2008 to November 2008.
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 since 2005 with Penn West.
S. Keith Luft Alberta, Canada	General Counsel and Senior Vice President, Stakeholder Relations	General Counsel and Senior Vice President, Stakeholder Relations of Penn West since February 2008.
David W. Middleton Alberta, Canada	Executive Vice President, Operations Engineering and Managing Director, Peace River Oil Partnership	Executive Vice President, Operations Engineering and Managing Director, Peace River Oil Partnership since January 2013. Prior thereto, Executive Vice President, Managing Director, Peace River Oil Partnership of Penn West from June 2010 to January 2013. Prior thereto, Executive Vice President, Engineering and Corporate Development of Penn West from November 2008 to June 2010.Prior thereto, Executive Vice President, Operations and Corporate Development of Penn West from February 2008 to November 2008.
Bob Shepherd Alberta, Canada	Senior Vice President, Enhanced Oil Recovery and Cordova Joint Venture	Senior Vice President, Enhanced Oil Recovery and Cordova Joint Venture of Penn West since July 2011. Prior thereto, Senior Vice President, Exploration and Development of Penn West from October 2009 to July 2011. Prior thereto, Vice President, Exploitation of Penn West from January 2009 to October 2009. Prior thereto, President of Laser Energy Inc., a private oil and natural gas company, from 2007 to 2009.
Todd H. Takeyasu Alberta, Canada	Executive Vice President and Chief Financial Officer	Executive Vice President and Chief Financial Officer of Penn West since February 2008.

Name, Province and Country of Residence	Positions and Offices Held with Penn West	Principal Occupations during the Five Preceding Years
Robert Wollmann Alberta, Canada	Senior Vice President, Exploration	Senior Vice President, Exploration of Penn West since February 2012. Prior thereto, Vice President, Exploration of Penn West from July 2011 to February 2012. Prior thereto, Senior Manager, Geosciences of Penn West from June 2010 to July 2011. Prior thereto, Senior Geotechnical Advisor of Penn West from September 2009 to June 2010. Prior thereto, President, Chief Executive Officer and a director of Trafalgar Energy Ltd., a public oil and natural gas company subsequently renamed as Midway Energy Ltd.

Notes:

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

As at March 13, 2013, the directors and executive officers of Penn West, as a group, beneficially owned, or controlled or directed, directly or indirectly, two 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, 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.

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, 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.

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 13, 2013, the members of the Audit Committee are James C. Smith, Chairman, James E. Allard, Gillian H. Denham, George H. Brookman and Frank Potter, 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.

James E. Allard

Mr. Allard is an independent director and business advisor. He has a Bachelor of Science degree in Business Administration from the University of Connecticut and completed the Advanced Management Program at Harvard University. Mr. Allard has focused his career on international finance in the petroleum industry for over 42 years, during which time he has served as the Chief Executive Officer, Chief Financial Officer and/or a director of a number of publicly traded and private companies. Over the past eleven years he has served on the board of the Alberta Securities Commission, acted as the sole external trustee and advisor to a mid-sized pension plan and served as a director and advisor to several companies. From 1981 to 1995, Mr. Allard served as a senior executive officer of Amoco Corporation and as a director of Amoco Canada, which at that time was Canada's largest natural gas producer. In addition, Mr. Allard is a member of the Institute of Corporate Directors.

George H. Brookman

Since 1984, Mr. Brookman has been the Chief Executive Officer of West Canadian Industries Group Inc., a digital printing and document management company. In 1984, Mr. Brookman acquired West Canadian Industries Group and under his leadership, it has become one of Canada's largest privately held digital printing and imaging service companies. He is also a partner in Vistek, a major retail camera operation with stores in Toronto, Ottawa, Mississauga, Calgary and Edmonton. He was also the founder of Commonwealth Legal Inc., Canada's only national litigation support services company. Prior to acquiring West Canadian Industries Group, Mr. Brookman was involved for many years in the commercial development industry in the Real Estate Group at Manulife and later as the Vice President of ATCO Development Ltd. In addition to his over 35 years of business experience, Mr. Brookman has been active in the community and is currently the Chairman of the Board for Tourism Calgary and Immediate Past President and Chairman of the Calgary Exhibition and Stampede. In addition, Mr. Brookman is a member of the Institute of Corporate Directors.

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 Executive Director of the World Bank in Washington where he served for nine years. 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 Limited and the Royal Ontario Museum, and has experience serving on audit committees for several public issuers.

Pre-Approval Policies and Procedures for 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 shall 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 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] ($)
2012	1,120,000	146,000	38,000
2011	1,230,000	157,500	—

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.

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

Following the completion of the Corporate Conversion, the Board of Directors adopted a quarterly dividend policy with an initial dividend rate of Cdn$0.27 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.

Distributions Declared Payable to Unitholders of Penn West Trust

During the financial year ended December 31, 2010, Penn West Trust declared payable the following amount of cash distributions per Trust Unit:

Month	2010 Distributions Declared Payable ($)
January	0.15
February	0.15
March	0.15
April	0.15
May	0.15
June	0.15
July	0.15
August	0.15
September	0.09
October	0.09
November	0.09
December	0.09
Total	1.56

Note:

(1) The Corporate Conversion was completed on January 1, 2011. This table references cash distributions declared payable on the Trust Units during the financial year ended December 31, 2010, prior to the completion of the Corporate Conversion.

Dividends Declared Payable to Shareholders of Penn West

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

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

Note:

(1) The Corporate Conversion was completed on January 1, 2011. This table references cash dividends declared payable on the Common Shares during the two financial years ended December 31, 2012 and December 31, 2011, respectively, following the completion of the Corporate Conversion.

MARKET FOR SECURITIES

Trading Price and Volume

Following the completion of the Corporate Conversion, the Common Shares were listed on the TSX under the symbol PWT on January 10, 2011 and on the NYSE under the symbol PWE on January 3, 2011. The Trust Units were delisted from the TSX and the NYSE on the same dates that the Common Shares were listed. The following tables set forth certain trading information for the Common Shares in 2012 as reported by the TSX and the NYSE.

	TSX		
Period	Common Share price ($) High	Common Share price ($) Low	Volume
January	22.09	20.45	26,308,640
February	22.22	20.65	27,653,447
March	22.10	19.23	26,337,464
April	19.65	16.26	33,079,106
May	17.14	13.35	28,004,249
June	14.64	12.65	25,825,846
July	14.87	12.51	35,524,412
August	15.12	13.34	24,593,931
September	16.15	13.63	25,599,348
October	14.25	12.89	29,623,306
November	13.12	10.28	28,810,948
December	11.88	10.42	22,244,674

	NYSE		
Period	Common Share price ($US) High	Common Share price ($US) Low	Volume
January	21.86	20.29	32,870,816
February	22.21	20.88	35,895,500
March	22.15	19.51	34,038,353
April	19.70	16.73	32,297,002
May	17.35	13.15	51,618,872
June	14.29	12.48	41,519,697
July	14.18	12.31	37,874,203
August	15.06	13.26	35,089,743
September	16.44	13.90	33,200,040
October	14.37	12.98	31,188,441
November	13.07	10.43	59,717,899
December	11.81	10.59	33,028,980

Prior Sales

Other than incentive securities issued pursuant to Penn West's equity 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 equity 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 agreements among 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. It is not expected that any of these regulations or controls will affect our operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. 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 may also be 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 current 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* which received Royal Assent on June 29, 2012 (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 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 became effective 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.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which 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. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40 percent. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/$m^3$ compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36 percent. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

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 taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

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.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008, with the intention to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 metres) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. Production from wells operating under the transitional royalty rates will not be subject to the royalty curves for conventional oil and natural gas.

On March 17, 2011, the Government of Alberta approved the *New Well Royalty Regulation* providing for the permanent implementation of a formerly temporary royalty program which provides for a maximum 5% royalty rate for eligible new wells for the first 12 productive months or until the regulated "volume cap" is reached.

In addition to the foregoing, 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 at that time 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, currently at a rate of $3.50 per hectare, 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 based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (“**old oil**”), between October 31, 1975 and June 1, 1998 (“ **new oil**”), or after June 1, 1998 or through an enhanced oil recovery (“ **EOR**”) scheme (“**third-tier oil**”). 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, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to oil production on Crown land. 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 freehold production tax rate for natural gas liquids is a flat 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:

- *Summer Royalty Credit Program* providing a royalty credit equal to 10 percent of goods and services costs up to $100,000 for wells drilled between April 1 and November 30 of each year;
- *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;
- *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;
- *Natural Gas Royalty Reduction* providing a reduced royalty on wells drilled on land rights acquired after June 1, 1998 and completed within five years of the date the rights are issued;
- *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 monthly royalty reductions for low productivity non- conservation natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow non-conservation natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of horizontal wells, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; 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.

In August 2012, the Government of British Columbia announced that it is implementing a nominal two percent royalty on both oil and natural gas revenues derived during the first year of production for wells drilled from September 2012 through to June 2013.

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 (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects) or new oil (oil from wells drilled on or after January 1, 1994). Southwest designated oil uses the same definitions of third and fourth tier oil but 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 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, 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 actual price received, 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 more than 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. Natural gas liquids and by-products recovered at gas processing plants are not subject to a royalty. Gas liquids which are produced and measured at the wellhead are treated as crude oil for royalty purposes.

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 $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 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 **c**ertain 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 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 from the Minister. 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 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 and natural gas 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 for injection, or converted to injection wells, in an approved enhanced recovery project, earn a one year holiday for portions of the project area. Under the Program, wells drilled for purposes of injection (or wells converted to injection wells prior to producing predetermined volumes of oil) in an approved EOR 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*:

- *New Well Incentive* provides licensees of newly drilled, non-horizontal wells drilled prior to January 1, 2014 with a holiday oil volume to a maximum of 10,000 m^3;
- *Deep Drilling Incentive* provides licensees who drill a well to a total depth sufficient to penetrate the Devonian Duperow formation with a holiday oil volume of up to 20,000 m^3, and licensees who drill a well deeper than the Devonian Three Forks formation can make a one-time assignment of up to 10,000 m^3 of holiday oil volume earned through previous drilling or major workovers to such well's holiday oil volume;
- *Horizontal Well Initiative* provides licensees of horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m^3, and the first horizontal leg (unless otherwise approved) drilled from an existing horizontal well on or after January 1, 2009 and prior to January 1, 2014 (and more than one year after the finished drilling date of the well), will earn an additional holiday royalty volume of 3,000 m^3;
- *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2014 with a holiday oil volume of 500 m^3, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 1 m^3 per operating day; and
- *Injection Well Incentive* provides a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to water injection.

Further, holiday oil volumes earned by a newly drilled well or a marginal well that has undergone a major workover can be transferred to a Holiday Oil Volume Account at the request of the licensee, the purpose of which is to optimize the value of holiday oil volumes earned by providing a company with the flexibility of allocating holiday oil volumes earned among new wells.

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. Leases and licences that were granted prior to January 1, 2009, but continued after that date, are not subject to shallow rights reversion until they continue past their primary term (at which time the application of deep rights reversion occurs). Afterwards, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location.

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 emission 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 *Jobs, Growth and Long-term Prosperity Act* (Canada) which received Royal Assent in June 2012, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. 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

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 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**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be 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, leases, licenses, 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 effect on September 1, 2012. The LARP covers approximately 93,212 square kilometres of land located in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 per cent of the provinces oilsands resource and much of the Cold Lake oilsands area. LARP establishes six new conservation areas, bringing the total conserved land in the region to two million hectares, or 22 per cent. The Alberta government plans to pay $30 million to producers whose leases will be cancelled in areas set aside for conservation. Oil and gas companies will be allowed to continue to operate in conservation and recreation areas however oilsands companies' tenures will be cancelled. New petroleum and gas tenure sold in conservation areas will include a restriction that prohibits surface access. Application procedures for activities and facilities in the LARP, regulated by the Energy Resources Conservation Board and the Alberta Utilities Commission, respectively, have been changed to accommodate the new restrictions set out in the LARP. The LARP is the first of seven regions to get a land use plan. The next will be the South Saskatchewan region.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGCA**") impacts conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities. Under the OGCA, the B.C. Oil and Gas 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 OGCA requires the 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, and 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.

Climate Change Regulation

Federal

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 green house gases (" **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, which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although the intention was for draft regulations for the implementation of the Updated Action Plan to become binding on January 1, 2010, the only regulations announced pertain to carbon dioxide emissions from coal-fired generation of electricity (finalized in the summer of 2012). Further, 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. As a result, it is unclear to what extent implementation of the proposals contained in the Updated Action Plan will occur.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it would issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline or the November 10, 2012 deadline. However, in March 2012, the EPA proposed a strict GHG standard on new power plants only. While it is expected that this rule could encourage building new natural gas power plants rather than coal plants, the actual effect of the new rule will not be able to be quantified for some time.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it 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 similar to the Updated Action Plan and aims for a 50 percent reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction 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 to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, and 10% of their baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. 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. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can 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 *Specified Gas Emitters Regulation*. However, we do have minor working interests in non-operated facilities that are subject to the CCEMA and the *Specified Gas Emitters Regulation*. As at the date hereof, we do not believe that our financial obligations associated with such non-operated facilities are material.

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 2012, 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 will undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review will cover all aspects of the carbon tax, including revenue neutrality, and will consider the impact on the competitiveness of British Columbian businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. Under this comprehensive review, British Columbians can make written submissions to the province's Minister of Finance, and these submissions will be considered as part of the 2013 Budget process.

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 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. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20 percent reduction in GHG emissions from 2006 levels by 2020.

Manitoba

The Government of Manitoba has commenced public consultations with respect to the development of a cap and trade system to reduce GHG emissions; however, no legislation is currently in effect in Manitoba. In June 2007, Manitoba joined the Western Climate Initiative ("**WCI**"), which was established to identify, evaluate and implement collective, co-operative ways to reduce GHGs within a specified region. The regional partners who form the WCI focus on a market based cap and trade system, and additional reduction opportunities through complementary measures. WCI regional partners include seven U.S. states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces (British Columbia, Manitoba, Ontario and Québec). The WCI's goal is to reduce GHG emissions in the region by 15 percent below 2005 levels by 2020. When fully implemented in 2015, the WCI aims to cover nearly 90 percent of the region's emissions.

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 reducing 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 and ongoing into 2013, 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 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 availability of transportation infrastructure;
- 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 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 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 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, particularly in Europe.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, geo-political events, OPEC actions 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. Although our business and asset base have not changed materially, the lending capacity of certain financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, our ability to make capital expenditures will be dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular.

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.

At March 13, 2013, we had approximately $1.9 billion of unused credit available under our credit facilities. Based on current funds available and expected cash from operations, we believe that we have sufficient funds available to fund our projected capital expenditures. However, if cash flow from operations is lower than expected or capital costs for our projects exceeds current estimates, or if we incur major unanticipated expenses related to the development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain financing necessary for our capital expenditure plans may result in a delay in development or production on our properties and/or a decrease of the amount of cash dividends that we pay to Shareholders.

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.

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 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.

As a result of such increasing competition, it has become (and we expect it to continue to be) more difficult to acquire producing assets and reserves on accretive terms. We also compete for skilled industry personnel with a substantial number of other oil and gas companies.

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.

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.

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. In recent years, the Canadian dollar has increased materially in value against the United States dollar and has at times traded above par against the United States dollar. Any such material increases in the value of the Canadian dollar 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 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.

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, GLJ and Sproule have 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 Reports summarized herein, and such variations could be material. The Engineering Reports summarized herein are 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 Reports 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 Reports summarized herein. The reserves evaluations described herein are effective as of a specific date and, except as otherwise noted, have not been updated and thus do not reflect changes in our reserves since that date.

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.

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. The legislation also requires that wells, pipelines and associated facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. 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 regulations, 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 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 greenhouse gases and require us to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. 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 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.

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".

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.

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.

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.

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.

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 (exploration, 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 licenses from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits 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).

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; 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.

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 PROP and the Cordova JV. 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.

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.

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 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.

We do not operate all of our properties and facilities. Therefore, our results of operations may be adversely affected by pipeline interruptions and apportionments and 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, processing and pipeline 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, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, 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. 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.

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.

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 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.

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.

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, 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.

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.

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.

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.

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 producing 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.

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.

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.

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.

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.

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”.

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.

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 all of our 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 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.

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

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

The primary differences between the Canadian and United States reporting requirements include the following: (i) the Canadian standards require disclosure of proved and probable reserves, while the U.S. standards require disclosure of only proved reserves; (ii) the Canadian standards permit the disclosure of oil and gas resources, while the U.S. standards prohibit such disclosure; (iii) the Canadian standards require the use of forecast prices in the estimation of reserves, while the U.S. standards require the use of 12-month average prices which are held constant; (iv) the Canadian standards require disclosure of reserves on a gross (before royalties) and net (after royalties) basis, while the U.S standards require disclosure on a net (after royalties) basis; (v) the Canadian standards require disclosure of production on a gross (before royalties) basis, while the U.S. standards require disclosure on a net (after royalties) basis; and (vi) the Canadian standards require that reserves and other data be reported on a more granular product type basis than required by the U.S. standards.

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.

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 in the market. PP&E or E&E asset write-downs may also be reversed to earnings in future periods should the conditions that caused impairment reverse.

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 assessed 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, 2012, we had approximately $2 billion recorded on our balance sheet as goodwill arising from historical acquisitions. An impairment would result in a write-down of the goodwill value and a non-cash charge against income, which may be viewed unfavourably in the market. Goodwill impairments are not allowed to be reversed in future periods. The calculation of impairment value is subject to management estimates and assumptions.

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 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.

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 13, 2013, approximately $1.1 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$1,634 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 mature starting in 2014 continuing until 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.

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.

An increase in the price of diluents would negatively impact the profitability of our heavy oil and bitumen projects.

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluents are required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluents may cause their price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing our overall operating cost, decreasing our net revenues and negatively impacting the overall profitability of our heavy oil and bitumen projects.

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 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.

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 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 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.

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 CIBC Mellon 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 GLJ and Sproule, our independent engineering evaluators (GLJ and Sproule 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 Penn West and have confirmed that they are independent with respect to Penn West within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and within the meaning of the applicable rules and regulations of the SEC and the Public Company Accounting Oversight Board (United States).

No director, officer or employee of GLJ, Sproule 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 financial statements and 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

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, 2012, estimated using forecast prices and costs.

Independent qualified reserves evaluators (or in some cases qualified reserves auditors) have evaluated (or in some cases audited) Penn West's reserves data. The report of the independent qualified reserves evaluators (or in some cases qualified reserves auditors) 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 evaluators (or in some cases qualified reserves auditors);

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

(c) reviewed the reserves data with management and the independent qualified reserves evaluators (or in some cases qualified reserves auditors).

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 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 evaluators (or in some cases qualified reserves auditors) on the reserves data; and

(c) the content and filing of this report.

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

(signed) *"Murray R. Nunns"*
President and Chief Executive Officer

(signed) *"Todd Takeyasu"*
Executive Vice President and Chief Financial Officer

(signed) *"Daryl Gilbert"*
Director and Chairman of the Reserves Committee

(signed) *"Jack Schanck"*
Director and Member of the Reserves Committee

March 13, 2013

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 (or in some cases audited) Penn West's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, 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 (or in some cases our audit).

   We carried out our evaluation (or in some cases our 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 (or in some cases an audit) to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation or 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 and audited by us for the year ended December 31, 2012, 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	Net Present Value of Future Net Revenue (millions before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	January 31, 2013	Canada	$ —	$ 4,420	$ —	$ 4,420
Sproule Associates Limited	February 22, 2013	Canada	$2,011	$ 2,699	$ —	$ 4,710
Sproule Associates Limited	February 22, 2013	USA	$ —	$ —	$ —	$ —
Totals			$2,011	$ 7,119	$ —	$ 9,130

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) *"GLJ Petroleum Consultants Ltd."*
GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada
March 13, 2013

(signed) *"Sproule Associates Limited"*
Sproule Associates Limited
Calgary, Alberta, Canada
March 13, 2013

APPENDIX A-3

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Our statement of reserves data and other oil and gas information dated March 13, 2013 is set forth below (the " **Statement**"). The effective date of the Statement is December 31, 2012 and the preparation date of the Statement is March 13, 2013. The Report of Management and Directors on Reserves Data and Other Information on Form 51-101F3 and the Report on Reserves Data by GLJ and 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: (i) an evaluation prepared by GLJ with an effective date of December 31, 2012 contained in the GLJ Report; and (ii) an evaluation and audit prepared by Sproule with an effective date of December 31, 2012 contained in the Sproule 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 with the requirements of NI 51-101. We engaged GLJ to evaluate approximately 48 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. We engaged Sproule to evaluate approximately 30 percent and to audit approximately 22 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 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, 2012
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (MMbbl)	Net (MMbbl)	Gross (MMbbl)	Net (MMbbl)
PROVED				
Developed Producing	163	140	44	40
Developed Non-Producing	4	4	1	1
Undeveloped	76	65	2	2
TOTAL PROVED	243	209	46	42
PROBABLE	108	89	44	38
TOTAL PROVED PLUS PROBABLE	351	298	90	81

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Bcf)	Net (Bcf)	Gross (MMbbl)	Net (MMbbl)
PROVED				
Developed Producing	641	564	21	15
Developed Non-Producing	32	27	1	1
Undeveloped	100	89	5	4
TOTAL PROVED	773	680	27	20
PROBABLE	413	349	11	8
TOTAL PROVED PLUS PROBABLE	1,186	1,029	38	28

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (MMboe)	Net (MMboe)
PROVED		
Developed Producing	334	290
Developed Non-Producing	11	9
Undeveloped	99	86
TOTAL PROVED	445	384
PROBABLE	231	194
TOTAL PROVED PLUS PROBABLE	676	578

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2012
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	10,179	7,151	5,603	4,659	4,017	19.35	3.23
Developed Non-Producing	312	220	167	134	112	18.18	3.03
Undeveloped	2,896	1,620	942	541	284	11.00	1.83
TOTAL PROVED	13,387	8,990	6,713	5,334	4,413	17.46	2.91
PROBABLE	8,031	4,033	2,417	1,604	1,133	12.48	2.08
TOTAL PROVED PLUS PROBABLE	21,419	13,023	9,130	6,937	5,546	15.80	2.63

Note:

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

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2012
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	8,982	6,544	5,250	4,435	3,868
Developed Non-Producing	233	168	131	108	92
Undeveloped	2,170	1,171	637	320	117
TOTAL PROVED	11,385	7,882	6,018	4,862	4,077
PROBABLE	5,989	2,977	1,756	1,142	788
TOTAL PROVED PLUS PROBABLE	17,374	10,859	7,774	6,004	4,865

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2012
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	34,379	4,700	12,968	2,563	760	13,387	2,003	11,385
Proved Plus Probable Reserves	53,572	7,726	19,429	4,118	881	21,419	4,045	17,374

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (MM$)	UNIT VALUE[3] ($/bbl)	($/Mcf)
Proved Reserves	Light and Medium Crude Oil[1]	5,346	18.24	3.04
	Heavy Oil[1]	868	19.44	3.24
	Natural Gas[2]	464	11.85	1.97
	Non-Conventional Oil and Gas Activities	36	4.72	0.79
	TOTAL	6,713	17.46	2.91
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	7,075	16.62	2.77
	Heavy Oil[1]	1,403	16.82	2.80
	Natural Gas[2]	584	11.36	1.89
	Non-Conventional Oil and Gas Activities	67	3.86	0.64
	TOTAL	9,130	15.80	2.63

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 Reports 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 Reports were as set forth below. The price assumptions set forth below were provided by GLJ and Sproule.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

	OIL					EDMONTON LIQUIDS PRICES				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40ºAPI ($Cdn/bbl)	Lloydminster Blend 21ºAPI ($Cdn/bbl)	Cromer Medium 29ºAPI ($Cdn/bbl)	NATURAL GAS AECO ($Cdn/Mcf)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	INFLATION RATES[1] %/year	EXCHANGE RATE[2] ($US equals $1.00 Cdn)
Forecast										
2013	89.82	84.78	69.63	78.84	3.35	40.61	64.23	93.58	—	1.00
2014	91.21	90.67	75.26	83.42	3.78	47.98	68.71	97.05	1.8	1.00
2015	91.64	91.10	75.62	83.81	4.09	52.93	69.06	96.10	1.8	1.00
2016	96.51	95.97	80.13	88.77	4.71	55.86	72.72	101.27	1.8	1.00
2017	97.23	96.68	80.73	89.43	5.13	56.43	73.25	102.04	1.8	1.00
2018	97.95	97.41	81.34	90.11	5.31	56.82	73.80	102.81	1.8	1.00
2019	99.21	98.67	82.39	91.27	5.40	57.52	74.75	104.14	1.8	1.00
2020	100.95	100.40	83.84	92.88	5.50	58.51	76.06	105.97	1.8	1.00
2021	102.71	102.17	85.31	94.51	5.60	59.51	77.40	107.83	1.8	1.00
2022	104.51	103.96	86.81	96.16	5.70	60.54	78.76	109.72	1.8	1.00
Thereafter	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8%	1.8	—

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, 2012 were $2.79/Mcf for natural gas, $80.69/bbl for light and medium crude oil, $63.67/bbl for heavy oil and $53.75/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$)	Proved Plus Probable Reserves (MM$)
2013	994	1,233
2014	787	1,291
2015	519	997
2016	98	254
2017	19	35
2018 and subsequent	146	308
Total: Undiscounted for all years	2,563	4,118

We currently expect to fund the development costs of the reserves primarily through internally-generated funds flow.

There can be no guarantee that funds will be available or that we will allocate funding to develop all of the reserves attributed in the Engineering Reports. 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 the 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 anticipate that interest or other funding costs would make development of any property uneconomic.

5. Estimated future well abandonment costs related to reserve wells have been taken into account by GLJ and 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 GLJ and 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, 2012, using forecast price and cost estimates derived from the Engineering Reports.

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

	LIGHT AND MEDIUM OIL[2]			HEAVY OIL[2]			NATURAL GAS[2]		
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, 2011	288	113	401	51	22	73	783	452	1,235
Extensions	5	9	14	—	—	—	17	43	60
Improved Recovery[1]	24	19	44	3	24	27	12	10	21
Technical Revisions	7	(11)	(4)	3	(1)	3	138	(86)	51
Discoveries	—	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	4	1	6
Dispositions	(54)	(22)	(75)	(5)	(2)	(6)	(12)	(5)	(18)
Economic Factors	(1)	—	(2)	—	—	—	(46)	—	(47)
Production	(28)	—	(28)	(6)	—	(6)	(123)	—	(123)
December 31, 2012	243	108	351	46	44	90	773	413	1,186

Note:

(1) Improved recovery includes the following:

Infill Drilling	23	14	37	2	2	3	10	9	18

FACTORS	NATURAL GAS LIQUIDS[2] Gross Proved (MMbbl)	Gross Probable (MMbbl)	Gross Proved Plus Probable (MMbbl)	TOTAL OIL EQUIVALENT[2] Gross Proved (MMboe)	Gross Probable (MMboe)	Gross Proved Plus Probable (MMboe)
December 31, 2011	28	12	39	498	222	719
Extensions	1	1	1	9	17	25
Improved Recovery[1]	2	1	2	31	46	77
Technical Revisions	2	(1)	1	35	(27)	8
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	1	—	1
Dispositions	(1)	(1)	(2)	(61)	(25)	(87)
Economic Factors	(1)	—	(1)	(10)	—	(10)
Production	(4)	—	(4)	(58)	—	(58)
December 31, 2012	27	11	38	445	231	676

Notes:

(1) Improved recovery includes the following:

Infill Drilling	—	—	1	27	17	44

(2) Columns may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ and 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 Reports 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 Reports 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 three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (MMbbl)		Heavy Oil (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
Prior thereto	16,650	45,964	289	1,697	7,029	61,352	111	1,490
2010	16,274	50,827	250	814	28,321	83,035	620	2,105
2011	39,334	78,183	1,725	2,465	60,090	87,527	2,692	4,216
2012	24,143	75,657	989	2,192	24,429	99,784	1,690	4,896

GLJ and Sproule have assigned 99 MMboe of proved undeveloped reserves in the Engineering Reports under forecast prices and costs, together with $2,339 million of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Engineering Reports accounts for $1,688 million, or 72 percent, of the total forecast undiscounted capital expenditures for proved undeveloped reserves. These figures increase to $2,286 million, or 98 percent, during the first five years of the Engineering Reports. The majority of our proved undeveloped reserves evaluated in the Engineering Reports are attributable to future oil development from infill drilling 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 (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
Prior thereto	26,110	51,166	460	2,351	7,343	60,475	83	1,857
2010	10,947	36,180	760	1,413	52,102	111,843	498	2,370
2011	22,318	50,629	7,555	8,879	124,722	206,520	1,784	4,046
2012	26,764	57,699	23,758	33,966	53,210	184,245	1,295	3,729

GLJ and Sproule have assigned 126 MMboe of probable undeveloped reserves in the Engineering Reports under forecast prices and costs, together with $1,513 million of associated undiscounted future capital expenditures. Probable undeveloped capital spending in the first two forecast years of the Engineering Reports accounts for $726 million, or 48 percent, of the total forecast undiscounted future capital expenditures for probable undeveloped reserves. These figures increase to $1,359 million, or 90 percent, during the first five years of the Engineering Reports. The probable undeveloped reserves evaluated in the Engineering Reports 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.

We review suspended or standing well bores for reactivation, recompletion or sale and conduct abandonment programs for those well bores that do not meet our criteria. 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 opportunities for multi-location programs and continuous operations to reduce costs.

As of December 31, 2012, we expect to incur future A&R Costs in respect of approximately 18,765 net well bores and 2,339 facilities. The total amount of A&R Costs, net of estimated salvage values, that we expect to incur, including wells that extend beyond the 50-year limit in the Engineering Reports, 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, 2012	6,568	653
Anticipated to be paid in 2013	107	97
Anticipated to be paid in 2014	109	90
Anticipated to be paid in 2015	111	84
Total anticipated to be paid in 2013, 2014 and 2015	327	271

The above table includes certain A&R Costs, net of estimated salvage values, not included in the Engineering Reports and not deducted in estimating future net revenue as disclosed above. Escalated at two percent and undiscounted, the A&R Costs not deducted were $5,687 million, and escalated at two percent and discounted at 10 percent, these A&R Costs were $611 million.

OTHER OIL AND GAS INFORMATION

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

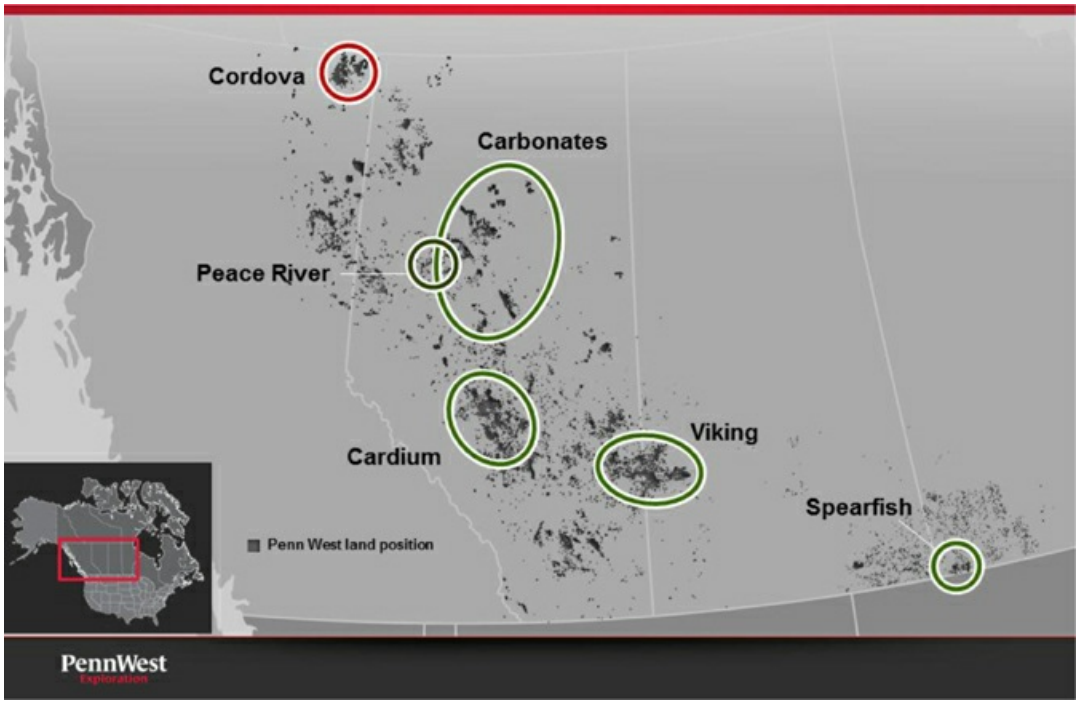
Introduction

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, 2012 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 200 producing properties. No single property accounts for more than six 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, 2012.



The following is a description of our principal oil and natural gas properties and related operations and activities as at December 31, 2012. Information in respect of gross and net acres and well counts are as of December 31, 2012 and information in respect of production is for the year ended December 31, 2012, 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.**

Spearfish Resource Play

The Spearfish resource play is a tight, light-oil play located near Waskada in southwestern Manitoba near the Canada/U.S. border. In 2012, Penn West focused on tight-oil development within the play and drilled approximately 85 net wells. It also expanded its oil processing infrastructure to accommodate higher production levels. Penn West held 75,000 net acres of developed and undeveloped land in the area as at December 31, 2012. In 2013, Penn West's Waskada area will be a key focus with current plans to drill 90 to 130 wells in the area.

Carbonates Resource Play

The Carbonates resource play is a tight, light-oil play situated north and northwest of Edmonton and extends through north-central Alberta encompassing Penn West's Slave Point and Swan Hills areas. In 2012, Penn West added key infrastructure and increased its oil and gas handling capacities in the Sawn Lake and Otter areas of the Slave Point. The 2012 capital program was focused on oil development in the Sawn Lake and Otter areas with over 40 net wells drilled. As at December 31, 2012, Penn West had a developed and undeveloped land position of approximately 500,000 net acres in the play. For 2013, Penn West has plans for a focused development program in the Slave Point area, notably in the Sawn Lake and Swan Hills areas and continuing its EOR strategies with the initiation of horizontal waterflood pilot projects at Sawn Lake and Otter.

Cardium Resource Play

The Cardium resource play is located in west central Alberta and extends from Calgary to Grande Prairie, Alberta. At December 31, 2012, 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 2012, Penn West's capital program included full-scale development in portions of the play and the drilling of approximately 45 net wells. In 2013, Penn West's capital budget includes selective drilling in the Alder Flats and West Pembina areas and further progression of its EOR strategy within the trend, including plans for two horizontal waterflood pilot projects in the Willesden Green area.

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 in this play with approximately 750,000 net acres of developed and undeveloped land at December 31, 2012. Penn West concentrated its 2012 capital program on oil development in the area with approximately 45 net wells drilled. During 2013, Penn West plans to drill 25 to 30 wells primarily in the Dodsland area and expand the infrastructure to support ongoing development programs into 2014 and beyond.

Peace River Assets

The Peace River Assets are a bitumen/heavy oil play located on oil sands leases in the Peace River area of northern Alberta. In June 2010, Penn West and the CIC Affiliate formed PROP to increase the pace of development of Penn West's resources in the area. Under the partnership, Penn West retained a 55 percent interest in the Peace River Assets, with the CIC Affiliate holding the remaining 45 percent interest.

PROP had a land position in this area comprised of approximately 243,000 gross acres of developed and undeveloped land at December 31, 2012. In 2012, PROP focused its activities on the thermal pilot project at Seal Main, continuing resource appraisal activities and conducting an appraisal development well drilling program. In 2013, capital plans include continued primary recovery and thermal recovery appraisal activities, the completion of additional engineering work at our Seal Main thermal pilot project and Seal Main commercial project, and further assessment of our Harmon Valley South thermal pilot.

For more information regarding the Peace River Assets and PROP, see "Description of our Business – General Development of the Business – Year Ended December 31, 2010 - Partnership and Equity Financing with Affiliate of China Investment Corporation".

Cordova Resource Play

The Cordova resource play is a natural gas focused play located in northeastern British Columbia in the Cordova Embayment. The play is operated as a joint venture that was formed in September 2010 and includes Penn West's legacy position at its Wildboy property, where significant production infrastructure exists.

The focus in this area is shale gas in the Cordova Embayment, located east of the Horn River development. The Cordova JV had approximately 250,000 net acres of developed and undeveloped land in the area at December 31, 2012. The capital program in 2012 was focused on resource appraisal. In 2013, Penn West expects to continue the evaluation of the play with further resource appraisal and assessment work.

For more information regarding the Cordova JV, see "Description of our Business – General Development of the Business – Year Ended December 31, 2010 - Joint Venture with Affiliate of Mitsubishi Corporation".

Enhanced Oil Recovery

Penn West believes that recent 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. Penn West currently operates successful steam injection, horizontal waterflood and CO_2 miscible flood pilot projects in several of its oil plays. In 2013, Penn West plans to initiate additional horizontal tight-oil waterflood projects.

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 which are capable of producing but which are not producing. For a discussion of our properties to which reserves have been attributed and which are capable of producing but which are not producing, see "Additional Information Relating to Reserves Data – Undeveloped Reserves" above.

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, 2012.

	Producing				Non-Producing		Total	
	Oil		Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	8,434	5,297	5,632	3,586	7,721	4,737	21,787	13,620
British Columbia	258	113	826	334	399	155	1,483	602
Saskatchewan	4,298	2,871	530	429	1,386	681	6,214	3,981
Manitoba	393	364	—	—	63	58	456	422
Northwest Territories	12	1	—	—	35	5	47	6
Wyoming	180	62	—	—	159	72	339	134
Montana	1	—	—	—	2	—	3	—
Total	13,576	8,708	6,988	4,349	9,765	5,708	30,329	18,765

Properties with no Attributed Reserves

The following table sets out the unproved properties in which we had an interest as at December 31, 2012.

	Unproved Properties (thousands of acres)	
	Gross	Net
Alberta	1,707	1,323
British Columbia	613	295
Saskatchewan	136	126
Manitoba	128	127
Northwest Territories	85	18
Wyoming	11	7
Total	2,680	1,896

We currently have no material work commitments on these lands. The primary lease or extension term on approximately 125,000 net acres of unproved property is scheduled to expire by December 31, 2013. 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 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 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, 2012, irrespective of whether such costs were capitalized or charged to expense when incurred.

	2012 MM$
Property Acquisition Costs[1]	
Proved Properties	(1,615)
Unproved Properties	37
Exploration Costs[1]	241
Development Costs[1]	1,595
Corporate Costs	16
Joint venture, carried capital	(137)
Total Capital Expenditures	137
Corporate Acquisitions	—
Total Expenditures	137

Note:

(1) "Property Acquisition Costs", "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, 2012.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	2	1	347	262
Natural Gas	5	2	18	17
Service	10	5	62	27
Stratigraphic test	—	—	—	—
Dry	—	—	—	—
Total	17	8	427	306

We currently estimate that our capital expenditures in 2013 will be approximately $900 million with an option to layer in up to $300 million in incremental capital, subject to commodity prices, crude oil differential realizations, demonstrating expected capital efficiencies, ongoing strategic portfolio management and Board approval. The primary components of our programs are described under the heading "Other Oil and Gas information – Description of Our Properties, Operations and Activities in Our Major Operating Regions".

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2013 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 (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	53,008	45,270	14,439	12,689	265,080	232,929	8,232	6,115	119,859	102,895
Proved Developed Non- Producing	1,049	940	343	322	3,745	3,190	96	77	2,112	1,871
Proved Undeveloped	12,403	11,214	1,019	928	12,147	11,189	937	853	16,383	14,860
Total Proved	66,460	57,424	15,801	13,939	280,972	247,308	9,265	7,044	138,355	119,626
Total Probable	4,628	3,949	1,484	1,248	21,249	18,659	527	442	10,180	8,749
Total Proved Plus Probable	71,088	61,374	17,284	15,187	302,220	265,967	9,792	7,486	148,535	128,375

No one field (being a defined geographical area consisting of one or more pools) accounts for more than eight percent of the estimated production 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 production, product prices received, royalties paid, production costs and resulting netback for the periods indicated below:

	Quarter Ended 2012				Year Ended December 31, 2012
	March 31	June 30	September 30	December 31	
Share of Average Gross Daily Production					
Light and Medium Crude Oil (bbl/d)	77,414	75,578	78,356	72,468	75,951
Heavy Oil (bbl/d)	18,170	17,222	17,213	16,847	17,361
Gas (MMcf/d)	361	351	329	329	342
NGLs (bbl/d)	11,615	11,958	10,019	9,756	10,832
Combined (boe/d)	167,420	163,181	160,339	153,931	161,195
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	87.65	78.74	76.67	78.90	80.50
Heavy Oil ($/bbl)	72.68	61.36	60.30	59.85	63.67
Gas ($/Mcf)	2.29	1.98	2.29	3.28	2.45
NGLs ($/bbl)	60.91	52.78	46.73	53.69	53.75
Combined ($/boe)	57.59	51.06	51.56	54.10	53.60
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	17.04	16.35	15.09	14.25	15.69
Heavy Oil ($/bbl)	10.07	8.51	8.76	8.63	9.01
Gas ($/Mcf)	0.22	0.18	0.28	0.69	0.34
NGLs ($/bbl)	16.53	13.35	13.58	15.37	14.71
Combined ($/boe)	10.59	9.84	9.74	10.10	10.07

	Quarter Ended 2012				Year Ended December 31, 2012
	March 31	June 30	September 30	December 31	
Production Costs[1][2]					
Light and Medium Crude Oil ($/bbl)	24.13	22.99	21.19	22.51	22.70
Heavy Oil ($/bbl)	19.43	19.43	19.22	19.22	19.32
Gas ($/Mcf)	2.16	2.08	2.13	2.09	2.11
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	17.93	17.16	16.78	17.16	17.26
Transportation					
Light and Medium Crude Oil ($/bbl)	—	—	—	—	—
Heavy Oil ($/bbl)	0.09	0.12	0.06	0.03	0.07
Gas ($/Mcf)	0.22	0.23	0.23	0.24	0.23
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	0.49	0.51	0.48	0.51	0.50
Risk Management Contracts Loss (Gain)					
Light and Medium Crude Oil ($/bbl)	4.88	1.01	(6.26)	(0.23)	(0.19)
Heavy Oil ($/bbl)	—	—	—	—	—
Gas ($/Mcf)	(0.47)	(0.35)	(0.32)	(0.19)	(0.34)
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	1.24	(0.29)	(3.72)	(0.51)	(0.81)
Netback Received[3]					
Light and Medium Crude Oil ($/bbl)	41.60	38.40	46.66	42.37	42.31
Heavy Oil ($/bbl)	43.09	33.30	32.26	31.97	35.27
Gas ($/Mcf)	0.16	(0.16)	(0.03)	0.45	0.11
NGLs ($/bbl)	44.37	39.43	33.15	38.32	39.04
Combined ($/boe)	27.34	23.84	28.28	26.84	26.58

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 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, 2012, Penn West produced 58 MMboe, comprised of 28 MMbbl of light and medium oil, six MMbbl of heavy oil, 123 Bcf of natural gas and four 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, approximately 73 percent is light and medium oil, 16 percent is conventional heavy oil and 11 percent is NGLs. In regard specifically to crude oil, our average quality is 33 degrees API, which is 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:

	2012		2011		2010	
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	84.16	72.68	79.76	62.79	72.72	64.31
June 30	75.20	61.36	94.29	72.81	67.70	57.03
September 30	73.28	60.30	82.23	63.38	65.68	58.81
December 31	75.91	59.85	88.76	76.88	71.05	61.87

Natural Gas Marketing

In 2012, we received an average price from the sale of natural gas, before adjustments for hedging activities, of $2.45/Mcf compared to $3.78/Mcf realized in 2011. 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 15 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. 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, 2012, 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 11 to our audited consolidated financial statements as at and for the year ended December 31, 2012, 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**") 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 impairment calculation;

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

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

(v) review of decommissioning liabilities 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(b) of the Corporate Governance Rules of the New York Stock Exchange.

(d) All of the members must be “financially literate” within the meaning of NI 52-110 and Section 303A.07(a) of the Corporate Governance Rules of the New York Stock Exchange 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 (g) 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.

Exhibit 99.2

MANAGEMENT'S DISCUSSION AND ANALYSIS
For the year ended December 31, 2012

This management's discussion and analysis ("MD&A") of financial conditions and results of operations should be read in conjunction with the audited consolidated financial statements and accompanying notes of Penn West Petroleum Ltd. ("Penn West", "We", "Our", the "Company") for the years ended December 31, 2012 and 2011. The date of this MD&A is March 13, 2013. All dollar amounts contained in this MD&A are expressed in millions of Canadian dollars unless noted otherwise.

For additional information, including our audited consolidated financial statements and Annual Information Form, please go to our website at www.pennwest.com, in Canada to the SEDAR website at www.sedar.com or in the United States to the SEC website at www.sec.gov.

On January 1, 2011, we completed our plan of arrangement under which Penn West converted from an income trust to a corporation, operating under the trade name of Penn West Exploration. Prior to this date, our consolidated financial results were presented as an income trust, Penn West's former legal structure, as at and for the year ended December 31, 2010.

In the first quarter of 2011, we completed our change to International Financial Reporting Standards ("IFRS") from Canadian Generally Accepted Accounting Principles ("previous GAAP"). Our previously reported consolidated financial statements were adjusted to be in compliance with IFRS on January 1, 2010 (the "date of transition"). Previously reported results and balances subsequent to the date of transition have been revised to comply with IFRS.

Please refer to our advisory on forward-looking statements at the end of this MD&A. Barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of crude oil 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.

Certain measures including funds flow, funds flow per share-basic, funds flow per share-diluted, netback, return on equity and return on capital included in this MD&A are not defined within, nor have a standardized meaning prescribed by, IFRS or previous GAAP; accordingly, they may not be comparable to similar measures provided by other issuers. Funds flow is cash flow from operating activities before changes in non-cash working capital and decommissioning expenditures. Funds flow is used to assess our ability to fund dividend and planned capital programs. See below for reconciliations of funds flow to its nearest measure prescribed by IFRS. Netback is the per unit of production amount of revenue less royalties, operating costs, transportation and realized risk management and is used in capital allocation decisions and to economically rank projects. Return on equity is calculated by comparing net income to shareholders' equity and is used to measure a rate of return on shareholders' equity. Return on capital is calculated using net income excluding financing charges compared to shareholders' equity and long-term debt and is used as a measure to assess how well we employ the capital invested into the company.

Calculation of Funds Flow

	Year ended December 31	
(millions, except per share amounts)	**2012**	2011
Cash flow from operating activities	**$ 1,193**	$ 1,407
Increase (decrease) in non-cash working capital	**(37)**	49
Decommissioning expenditures	**92**	81
Funds flow	**$ 1,248**	$ 1,537
Basic per share	**$ 2.62**	$ 3.29
Diluted per share	**$ 2.62**	$ 3.29

Annual Financial Summary

(millions, except per share amounts)	Year ended December 31		
	2012	2011	2010
Gross revenues [1]	**$ 3,283**	$ 3,604	$ 3,034
Funds flow	**1,248**	1,537	1,185
Basic per share	**2.62**	3.29	2.68
Diluted per share	**2.62**	3.29	2.65
Net income	**174**	638	1,110
Basic per share	**0.37**	1.37	2.51
Diluted per share	**0.37**	1.36	2.48
Capital expenditures, net [2]	**137**	1,580	(119)
Long-term debt at year-end	**2,690**	3,219	2,496
Convertible debentures	**—**	—	255
Dividends/ distributions paid [3]	**512**	420	708
Total assets	**$14,491**	$15,584	$14,543

(1) Gross revenues include realized gains and losses on commodity contracts.
(2) Excludes business combinations.
(3) Includes dividends paid and reinvested in shares under the dividend reinvestment plan.

2012 Highlights

- Funds flow for 2012 was $1,248 million ($2.62 per share – basic) compared to $1,537 million ($3.29 per share – basic) in 2011. The decline in funds flow was primarily attributed to lower commodity price realizations from wider Canadian crude oil differentials and lower natural gas prices.
- Net income for 2012 was $174 million ($0.37 per share – basic); a decrease from the $638 million ($1.37 per share – basic) in 2011. Net income was lower in 2012 primarily due to lower revenues related to lower commodity price realizations, an impairment charge on certain of our natural gas assets as a result of lower natural gas prices, partially offset by gains on asset dispositions, and gains from risk management items. Results for 2011 included a one-time deferred tax recovery of $304 million as a result of our conversion to a corporation.
- Annual 2012 production of 161,195 boe per day was within our previous guidance, compared to 163,094 boe per day for 2011. Production in 2012 was weighted approximately 65 percent to oil and liquids compared to 63 percent in 2011.
- Total net capital expenditures in 2012 of $137 million compared to $1,866 million in 2011 were within our previous guidance of $1.3 to $1.4 billion net of divestments closed to the end of the third quarter.
- In 2012, we closed net dispositions of $1,615 million with average production of approximately 16,500 boe per day.
- Netback was $26.58 per boe compared to $30.95 per boe in 2011, due primarily to a decline in commodity price realizations.

Quarterly Financial Summary
(millions, except per share and production amounts) (unaudited)

Three months ended	**Dec. 31 2012**	Sep. 30 2012	June 30 2012	Mar. 31 2012	Dec. 31 2011	Sep. 30 2011	June 30 2011	Mar. 31 2011
Gross revenues [1]	**$ 799**	$ 840	$ 774	$ 870	$ 979	$ 861	$ 920	$ 844
Funds flow	**295**	344	272	337	437	348	396	356
Basic per share	**0.62**	0.72	0.57	0.71	0.93	0.74	0.85	0.77
Diluted per share	**0.62**	0.72	0.57	0.71	0.93	0.74	0.85	0.77
Net income (loss)	**(53)**	(67)	235	59	(62)	138	271	291
Basic per share	**(0.11)**	(0.14)	0.50	0.12	(0.13)	0.29	0.58	0.63
Diluted per share	**(0.11)**	(0.14)	0.50	0.12	(0.13)	0.29	0.58	0.63
Dividends declared	**129**	129	128	128	127	127	127	125
Per share	**$ 0.27**	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.27
Production								
Liquids (bbls/d) [2]	**99,071**	105,588	104,758	107,199	108,071	101,392	98,998	104,349
Natural gas (mmcf/d)	**329**	329	351	361	364	360	343	371
Total (boe/d)	**153,931**	160,339	163,181	167,420	168,801	161,323	156,107	166,135

(1) Gross revenues include realized gains and losses on commodity contracts.
(2) Includes crude oil and natural gas liquids.

Business Strategy

Over the past several years, we have focused our capital activities to appraise the application of horizontal multi-stage fracture technology across our light-oil plays in Western Canada. These efforts have resulted in a significant inventory of light-oil targets. We completed these appraisal activities while providing a meaningful dividend to our shareholders. As we enter 2013, we remain committed to providing a dividend as we shift our focus to improving capital efficiencies and production reliability. Our 2013 capital budget is set at $900 million with the possibility of an additional $300 million depending on external market factors and internal performance. Our business strategy remains centered on realizing the value inherent in our extensive light-oil weighted asset base for the benefit of our shareholders.

Business Environment

Average 2012 benchmark crude oil prices remained range bound with WTI averaging US$94.17 per barrel compared to US$95.14 per barrel in 2011 and Brent averaging US$111.64 per barrel compared to US$111.11 per barrel in 2011. Ongoing issues in the Middle East and Africa, notably in Syria, Libya and Iran, led to future supply concerns and supported an upward movement in crude oil prices. These geopolitical issues were more than offset by Europe's sovereign debt concerns, U.S. fiscal cliff risks and uncertainty regarding China's economic growth rate.

Canadian oil price realizations were more volatile in 2012 than in recent history. Extended refinery turnarounds combined with North American production increases from plays such as the Canadian oil sands and the U.S. Bakken and Eagle Ford shale plays put pressure on North American oil infrastructure. The delay in the U.S. approval of the Keystone XL pipeline in January 2012 contributed to a risk averse tone in crude oil markets. In 2012, Edmonton light sweet crude averaged, on a monthly basis, between a US$20.02 discount per barrel and a US$3.61 premium per barrel compared to WTI, reaching its widest discount in March 2012. The benchmark Canadian heavy oil stream, Western Canadian Select ("WCS"), traded in the range of US$9.74 to US$32.98 per barrel less than WTI in 2012.

To date in 2013, the economic climate in Europe and Asia has shown signs of improvement and the U.S. has taken steps toward resolving its fiscal and budgetary problems. Geo-political concerns related to Syria and Iran persist and are expected to provide support to world oil prices in 2013. The Seaway project, which added 400,000 barrels per day of oil pipeline capacity from Cushing, Oklahoma to the U.S. Gulf Coast, came on stream in early 2013. Numerous other North American pipeline additions and expansions have been proposed to debottleneck North American oil. Many of these projects could be subject to environmental or other regulatory delays. The use of rail to deliver crude oil to markets has grown considerably, particularly in the U.S. Bakken play. In the first two months of 2013, WTI averaged approximately US$95.07 per barrel and Edmonton light sweet averaged $87.92 per barrel.

Despite lower drilling activity directed towards natural gas, production levels in the U.S. remained flat in 2012. This was attributed to associated gas production from high drilling levels for oil and natural gas liquids. On the demand side, last winter was one of the warmest on record which resulted in the highest end of the season natural gas inventory levels in history. This combination of high production and high inventory levels drove AECO day prices to an average low of $1.64 per mcf for the month of May. U.S. natural gas prices similarly declined to levels below coal on a BTU equivalent basis prompting some conversion in the power generation sector from coal to natural gas. The summer of 2012 was significantly warmer than average, further increasing natural gas demand for power generation which lowered inventory levels by the end of the summer compared to 2011. In late 2012, natural gas and coal equivalent prices were similar and the natural gas share of the power generation market ended close to pre-2012 levels. The AECO monthly price ended 2012 well off its lows for the year at $3.43 per mcf.

Crude Oil

Our average crude oil and liquids price for 2012, before the impact of the realized portion of risk management, was $74.91 per barrel (2011 – $83.22 per barrel). Currently, we have WTI collars on 55,000 barrels per day of our 2013 crude oil production between US$91.55 and US$104.42 per barrel.

Natural Gas

In 2012, the AECO Monthly Index averaged $2.40 per mcf compared to $3.67 per mcf in 2011. AECO monthly gas prices hit a low of $1.64 per mcf in May as inventory levels in North America reached historical highs.

Our corporate average natural gas price for 2012 before the impact of the realized portion of risk management was $2.45 per mcf (2011 – $3.78 per mcf). Currently, we have 125,000 mcf per day of natural gas production hedged for 2013 at an average price of $3.34 per mcf at AECO. We also have 25,000 mcf of natural gas production hedged for 2014 at an average price of $3.85 per mcf and an additional 50,000 mcf per day hedged through the use of collars with a floor of $3.41 per mcf and a ceiling of $4.18 per mcf.

Performance Indicators

Our management and Board of Directors monitor our performance based upon a number of qualitative and quantitative factors including:

- Finding and development (“F&D”) costs – We use these metrics to assess the continuing economic viability and the relative development stage of our resource plays.
- Base operations – Includes our production performance and execution of our operational, health, safety, environmental and regulatory programs.
- Shareholder value measures – These include key enterprise value metrics such as funds flow per share and dividends per share.
- Financial, business and strategic considerations – These include the management of our asset portfolio, financial stewardship and the overall goal of creating competitive return on investment for our shareholders.

Finding and Development costs

	Year ended December 31			
	2012	2011	2010	3-Year average
Adjusted F&D costs including future development costs ("FDC") [1]				
F&D costs per boe – proved plus probable	**$23.12**	$23.96	$23.39	$23.54
F&D costs per boe – proved	**$26.91**	$31.69	$25.25	$28.43
Excluding FDC [2]				
F&D costs per boe – proved plus probable	**$17.48**	$15.07	$18.90	$16.76
F&D costs per boe – proved	**$26.69**	$23.55	$21.50	$24.02
Including FDC [3]				
F&D costs per boe – proved plus probable	**$25.50**	$26.79	$26.73	$26.32
F&D costs per boe – proved	**$30.96**	$37.05	$28.01	$32.60

(1) The calculation of adjusted F&D includes the change in FDC and excludes the effects of acquisitions and dispositions and the effect of economic revisions related to downward revisions of natural gas prices.
(2) The calculation of F&D excludes the change in FDC and excludes the effects of acquisitions and dispositions.
(3) The calculation of F&D includes the change in FDC and excludes the effects of acquisitions and dispositions.

Our proved reserves continue to reflect a high percentage of developed reserves. Of total proved reserves, 78 percent were developed at December 31, 2012 (2011 – 80 percent). At December 31, 2012, total proved reserves as a percentage of proved plus probable reserves were 66 percent (2011 – 69 percent). On a proved plus probable basis our reserves continued to be weighted 71 percent to crude oil and liquids (2011 – 71 percent) and 29 percent to natural gas (2011 – 29 percent). Our successful tight-oil development activities and the application of techniques including waterflood and Enhanced Oil Recovery offset 2012 reserve dispositions which were predominately weighted towards oil. Economic revisions were primarily due to lower natural gas prices on base assets.

Capital expenditures for 2012 have been reduced by $137 million related to joint venture carried capital (2011 – $107 million). We use Adjusted F&D to assess the economic viability of our oil development programs. F&D costs are calculated in accordance with NI 51-101, which include the change in FDC, on a proved and proved plus probable basis. For comparative purposes we also disclose F&D costs excluding FDC.

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

Base operations

During 2012, we continued to consolidate our asset base and complete infrastructure development as we move through the development phase on many of our key light-oil plays. Our appraisal activities over the past few years have provided us with a significant inventory of light-oil targets. Our 2013 capital program is focused on improving capital efficiencies by allocating capital to areas we have significantly de-risked, where we have realized cost reductions and where we have infrastructure capacity.

Shareholder Value Measures

	Year ended December 31		
	2012	2011	2010
Funds flow per share	**$ 2.62**	$ 3.29	$ 2.68
Dividends/ distributions paid per share	**$ 1.08**	$ 0.90	$ 1.62
Ratio of year-end total long-term debt to annual funds	**2.2:1**	2.1:1	2.1:1

In April 2011, subsequent to converting to a corporation in January 2011, we began paying a quarterly dividend of $0.27 per share, which continued throughout 2012. Our last monthly distribution payment of $0.09 per unit as a trust was declared in December 2010 and paid in January 2011. In 2013, we plan to continue the rotation of our asset portfolio through the disposition of non-core properties and investment in our light-oil resources. We believe these strategies achieve a balance that provides our shareholders with a meaningful dividend as we continue to concentrate our asset base for oil growth.

Our total long-term debt to annual funds flow ratio has remained consistent over the last three years. As we look forward, we aim to grow our funds flow by oil and liquids production growth relative to both our long-term debt and dividend payout levels.

Financial, business and strategic considerations

	Year ended December 31		
	2012	2011	2010
Return on capital (1)	**3%**	7%	11%
Return on equity (2)	**2%**	7%	13%
Total assets (millions)	**$14,491**	$15,584	$14,543

(1) Net income before financing charges divided by average shareholders' equity and average total debt.
(2) Net income divided by average shareholders' equity.

The return on capital and return on equity ratios in 2012 and 2011 decreased as a result of lower net income. Net income was lower in 2012 primarily due to lower revenues related to lower commodity price realizations, an impairment charge on certain of our natural gas assets as a result of lower natural gas prices, partially offset by gains on asset dispositions, and gains from risk management items. Results for 2011 included a one-time income tax recovery of $304 million as a result of our conversion to a corporation. In 2010, we recorded significant gains on the formation of the Peace River Oil Partnership and the Cordova Joint Venture.

RESULTS OF OPERATIONS

Production

Daily production	Year ended December 31 2012	2011	% change
Light oil and NGL (bbls/d)	**86,783**	85,316	2
Heavy oil (bbls/d)	**17,361**	17,892	(3)
Natural gas (mmcf/d)	**342**	359	(5)
Total production (boe/d)	**161,195**	163,094	(1)

In 2012, we completed net property dispositions with combined production of approximately 16,500 boe per day, primarily weighted to oil. Our increase in light-oil production is the result of focusing our activities on light-oil plays, while our natural gas production declined in 2012 as a result of this strategy.

After the disposition of properties producing approximately 13,000 boe per day for approximately $1.3 billion during the fourth quarter of 2012, liquids production was approximately 62 percent of our production base exiting 2012. In 2013, we will continue to focus our capital activity on light-oil which should increase our weighting to liquids. Excluding the impact of net property dispositions, liquids production increased by approximately five percent from 2011.

When economic to do so, we strive to maintain an appropriate mix of liquids and natural gas production in order to reduce exposure to price volatility that can affect a single commodity. Given the weak outlook for natural gas prices and our significant inventory of light-oil locations, we currently plan to continue allocating substantially all of our capital investments to oil-weighted projects.

Average Sales Prices

	Year ended December 31 2012	2011	% change
Light oil and liquids (per bbl)	**$77.16**	$86.19	(10)
Risk management gain (loss) (per bbl) (1)	**0.17**	(2.03)	100
Light oil and liquids net (per bbl)	**77.33**	84.16	(8)
Heavy oil (per bbl)	**63.67**	69.07	(8)
Natural gas (per mcf)	**2.45**	3.78	(35)
Risk management gain (per mcf) (1)	**0.34**	—	100
Natural gas net (per mcf)	**2.79**	3.78	(26)
Weighted average (per boe)	**53.60**	60.99	(12)
Risk management gain (loss) (per boe) (1)	**0.81**	(1.06)	100
Weighted average net (per boe)	**$54.41**	$59.93	(9)

(1) Gross revenues include realized gains and losses on commodity contracts.

Netbacks

	Year ended December 31		
	2012	2011	% change
Light oil and NGL [1, 2]			
Production (bbls/day)	**86,783**	85,316	2
Operating netback (per bbl):			
Sales price	**$ 77.16**	$ 86.19	(10)
Risk management gain (loss) [3]	**0.17**	(2.03)	100
Royalties	**(15.57)**	(16.83)	(8)
Operating costs	**(19.86)**	(21.05)	(6)
Netback	**$ 41.90**	$ 46.28	(10)
Heavy oil			
Production (bbls/day)	**17,361**	17,892	(3)
Operating netback (per bbl):			
Sales price	**$ 63.67**	$ 69.07	(8)
Royalties	**(9.01)**	(10.01)	(10)
Operating costs	**(19.32)**	(17.53)	10
Transportation	**(0.07)**	(0.08)	(13)
Netback	**$ 35.27**	$ 41.45	(15)
Total liquids			
Production (bbls/day)	**104,144**	103,208	1
Operating netback (per bbl):			
Sales price	**$ 74.91**	$ 83.22	(10)
Risk management gain (loss) [3]	**0.14**	(1.68)	100
Royalties	**(14.48)**	(15.64)	(7)
Operating costs	**(19.77)**	(20.44)	(3)
Transportation	**(0.01)**	(0.01)	—
Netback	**$ 40.79**	$ 45.45	(10)
Natural gas			
Production (mmcf/day)	**342**	359	(5)
Operating netback (per mcf):			
Sales price	**$ 2.45**	$ 3.78	(35)
Risk management gain [3]	**0.34**	—	100
Royalties	**(0.34)**	(0.54)	(37)
Operating costs	**(2.11)**	(2.03)	4
Transportation	**(0.23)**	(0.22)	5
Netback	**$ 0.11**	$ 0.99	(89)
Combined totals			
Production (boe/day)	**161,195**	163,094	(1)
Operating netback (per boe):			
Sales price	**$ 53.60**	$ 60.99	(12)
Risk management gain (loss) [3]	**0.81**	(1.06)	100
Royalties	**(10.07)**	(11.09)	(9)
Operating costs	**(17.26)**	(17.40)	(1)
Transportation	**(0.50)**	(0.49)	2
Netback	**$ 26.58**	$ 30.95	(14)

(1) Excluded from the netback calculation is $72 million primarily related to realized risk management gains on our foreign exchange contracts which swap US dollar revenue at a fixed Canadian dollar rate.

(2) Included in the netback calculation is $48 million realized on the rearrangement of our 2013 oil collars which closed in the third quarter of 2012.

(3) Gross revenues include realized gains and losses on commodity contracts.

Production Revenues

Revenues from the sale of oil, NGL and natural gas consisted of the following:

(millions)	Year ended December 31		
	2012	2011	2010
Light oil and NGL	**$2,529**	$2,657	$1,965
Heavy oil	**405**	452	405
Natural gas	**349**	495	664
Gross revenues [1]	**$3,283**	$3,604	$3,034

(1) Gross revenues include realized gains and losses on commodity contracts.

Lower commodity price realizations in 2012, partially offset by an increase in liquids production, resulted in a decline in liquids revenue from 2011. Natural gas revenues were affected by lower production, due to our focus on light oil, and a significant decline in natural gas prices.

Crude oil prices increased in 2011 from 2010 which led to increases in both light and heavy-oil revenues. Also, contributing to the increase in light-oil revenues was higher light-oil production. Natural gas prices were lower in 2011 compared to 2010 resulting in a decline in natural gas revenues. Asset dispositions and a capital program concentrated on our light-oil properties led to the decline in natural gas production.

Reconciliation of Decrease in Production Revenues

(millions)	
Gross revenues – January 1 – December 31, 2011	$3,604
Increase in light oil and NGL production	53
Decrease in light oil and NGL prices (including realized risk management)	(181)
Decrease in heavy oil production	(12)
Decrease in heavy oil prices	(35)
Decrease in natural gas production	(23)
Decrease in natural gas prices	(123)
Gross revenues – January 1 – December 31, 2012	$3,283

Royalties

	Year ended December 31		
	2012	2011	2010
Royalties (millions)	**$ 595**	$ 661	$ 545
Average royalty rate [1]	**18%**	18%	18%
$/boe	**$10.07**	$11.09	$9.07

(1) Excludes effects of risk management activities.

Lower commodity prices in 2012, partially offset by the impact of wider Canadian crude oil differentials to WTI, resulted in lower royalties compared to 2011. Royalty rates remained consistent between 2012 and 2011.

An increase in crude oil prices in 2011 led to an increase in royalties compared to 2010. Royalty rates remained comparable in both 2011 and 2010 as lower royalty rates on new wells under the various royalty incentive programs partially offset higher royalty rates on base production.

Expenses

(millions)	Year ended December 31 2012	2011	2010
Operating	**$1,019**	$1,036	$ 944
Transportation	**29**	29	33
Financing	**199**	190	174
Share-based compensation	**$ (10)**	$ 84	$ 159

(per boe)	Year ended December 31 2012	2011	2010
Operating	**$17.26**	$17.40	$15.71
Transportation	**0.50**	0.49	0.55
Financing	**3.37**	3.20	2.89
Share-based compensation	**$(0.17)**	$ 1.41	$ 2.65

Operating

Operating costs were lower in 2012 than 2011 due to our focus on cost savings, lower electricity costs and acquisition and disposition activity. The temporary interruptions experienced in the second quarter of 2011 from the wild fires in Slave Lake and flooding in Manitoba and Saskatchewan led to increased workover and maintenance activity in 2011.

Operating costs for 2012 include a realized gain on electricity contracts of $7 million (2011 – $11 million gain and 2010 – $14 million loss). The average Alberta electricity pool price for 2012 was $64.31 per MWh compared to $76.21 per MWh in 2011 and $50.88 per MWh in 2010. We currently have the following contracts in place that fix the price of our electricity consumption; in 2013 approximately 50 MW fixed at $55.20 per MWh, in 2014 approximately 80 MW fixed at $58.50 per MWh, in 2015 approximately 55 MW fixed at $58.32 per MWh and in 2016 approximately 25 MW fixed at $49.90 per MWh.

Financing

The Company has an unsecured, revolving syndicated bank facility with an aggregate borrowing limit of $3.0 billion. The facility expires on June 30, 2016 and is extendible. The credit facility contains provisions for standby fees on unutilized credit lines and stamping fees on bankers' acceptances and LIBOR loans that vary depending on certain consolidated financial ratios. At December 31, 2012, approximately $2.2 billion was undrawn under this facility.

As at December 31, 2012, the Company had $1.9 billion (2011 – $2.0 billion) of senior unsecured notes outstanding with a weighted average interest rate, including the effects of cross currency swaps, of approximately 6.1 percent (2011 – 6.1 percent) and a weighted average remaining term of 5.5 years (2011 – 6.5 years). At December 31, 2012, the Company had $650 million of interest rate swaps outstanding at a weighted average fixed rate of 2.65 percent and an expiry date of January 2014. These swaps fix a portion of the interest rates under our bank facility.

At December 31, 2012, we had the following senior unsecured notes outstanding:

	Issue date	Amount (millions)	Term	Average interest rate	Weighted average remaining term
2007 Notes	May 31, 2007	US$475	8–15 years	5.80%	4.5 years
2008 Notes	May 29, 2008	US$480,CAD$30	8–12 years	6.25%	5.0 years
UK Notes	July 31, 2008	£57	10 years	6.95%(1)	5.6 years
2009 Notes	May 5, 2009	US$154 (2), £20, €10, CAD$5	5–10 years	8.85%(3)	4.0 years
2010 Q1 Notes	March 16, 2010	US$250,CAD$50	5–15 years	5.47%	5.8 years
2010 Q4 Notes	December 2, 2010, January 4, 2011	US$170,CAD$60	5–15 years	5.00%	8.7 years
2011 Notes	November 30, 2011	US$105,CAD$30	5–10 years	4.49%	7.1 years

(1) These notes bear interest at 7.78 percent in Pounds Sterling, however, contracts were entered to fix the interest rate at 6.95 percent in Canadian dollars and to fix the exchange rate on the repayment.
(2) A portion of the 2009 Notes have equal repayments, beginning in 2013, over the remaining seven years.
(3) The Company entered into contracts to fix the interest rate on the Pounds Sterling and Euro tranches, initially at 9.49 percent and 9.52 percent, to 9.15 percent and 9.22 percent, respectively, and to fix the exchange rate on repayment.

Financing charges in 2012 were slightly higher than in 2011 and 2010. In 2011, we repaid all outstanding convertible debentures and entered into additional fixed-rate, senior unsecured notes. While the Company's senior unsecured notes currently contain higher interest rates than drawings under our syndicated bank facilities held in short-term money market instruments, we believe the long-term nature inherent in the senior notes is favourable for a portion of our debt capital structure.

The interest rates on any non-hedged portion of the Company's credit facility are subject to fluctuations in short-term money market rates as advances on the credit facility are generally made under short-term instruments. As at December 31, 2012, four percent (December 31, 2011 – 19 percent) of our long-term debt instruments were exposed to changes in short-term interest rates.

Realized gains and losses on the interest rate swaps are recorded as financing costs. For 2012 an expense of $9 million (2011 – $12 million) was recorded in financing to reflect that the floating interest rate was lower than the fixed interest rate transacted under our interest rate swaps.

Share-Based Compensation

Share-based compensation expense is related to our Stock Option Plan (the “Option Plan”), our Common Share Rights Incentive Plan (the “CSRIP”), our Long-Term Retention and Incentive Plan (“LTRIP”), and our Deferred Share Unit Plan (the “DSU”).

Effective January 1, 2011, we implemented the Option Plan and amended our Trust Unit Rights Incentive Plan (“TURIP”) to become the CSRIP. Pursuant to our conversion from a trust to a corporation, TURIP holders had the choice to receive one restricted option (a “Restricted Option”) and one restricted right (a “Restricted Right”) for each outstanding “in-the-money” trust unit right. TURIP holders who chose not to make the election or held trust unit rights that were “out-of-the-money” on January 1, 2011, received one common share right (“Share Rights”) with the same terms under the CSRIP for each trust unit right. Subsequent to January 1, 2011, all grants are under the Option Plan.

Following the conversion to a corporation, the TURIP liability was removed and a share-based compensation liability was recorded for the Restricted Rights with the fair value charged to income. The fair values of the Restricted Options and Share Rights were also charged to income as at January 1, 2011, with an offset to other reserves. The elimination of the TURIP and subsequent implementation of the Option Plan and CSRIP resulted in a net $58 million charge to income during the first quarter of 2011.

The Restricted Options, Share Rights and subsequent grants under the Option Plan receive equity treatment for accounting purposes with the fair value of each instrument expensed over the expected vesting period based on a graded vesting schedule. The fair values of the Restricted Options and option grants are calculated using a Black-Scholes option-pricing model and the fair value of the Share Rights was calculated using a Binomial Lattice option-pricing model. The Restricted Rights are accounted for as a liability as holders may elect to settle in cash or common shares.

The change in the fair value of outstanding LTRIP awards is charged to income based on the common share price at the end of each reporting period plus accumulated dividends. The LTRIP obligation is accrued over the vesting period as service is completed by employees and expensed based on a graded vesting schedule. Subsequent increases and decreases in the underlying common share price will result in increases and decreases charged to income to adjust the LTRIP obligation to fair value until settlement.

Share-based compensation consisted of the following:

	Year ended December 31		
(millions)	**2012**	2011	2010
Options	**$ 21**	$ 18	$—
Restricted Options	**6**	22	—
Restricted Rights	**(45)**	(29)	—
Share Rights	**—**	1	—
LTRIP	**8**	14	8
TURIP	**—**	—	151
Expiry of TURIP at Jan. 1, 2011	**—**	(196)	—
Share Rights at Jan. 1, 2011	**—**	16	—
Restricted Options at Jan. 1, 2011	**—**	65	—
Restricted Rights liability at Jan. 1, 2011	**—**	173	—
Share-based compensation	**$(10)**	$ 84	$159

The share price used in the fair value calculation of the LTRIP liability and Restricted Rights obligation at December 31, 2012 was $10.80 per share (2011 – $20.19 and 2010 – $23.84).

General and Administrative Expenses ("G&A")

(millions, except per boe amounts)	Year ended December 31		
	2012	2011	**2010**
Gross	**$ 254**	$ 222	$ 207
Per boe	**4.31**	3.72	3.45
Net	**172**	142	145
Per boe	**$2.91**	$2.38	$2.41

In 2012, staff costs increased compared to the prior periods due to increasing activity levels consistent with our exploration & production company mandate.

In the fourth quarter of 2012, we incurred $13 million of restructuring charges related to an internal reorganization of departments which resulted in termination payouts for certain employees.

During 2012, we incurred a negligible amount (2011 – $1 million) of legal fees from a law firm of which a partner is also a director of Penn West.

Depletion, Depreciation, Impairment and Accretion

(millions, except per boe amounts)	Year ended December 31		
	2012	2011	2010
Depletion and depreciation ("D&D")	**$1,248**	$1,168	$1,169
D&D expense per boe	**21.17**	19.62	19.44
Impairment (recovery)	**277**	(10)	—
Impairment (recovery) per boe	**4.69**	(0.17)	—
Accretion of decommissioning liability	**54**	45	44
Accretion expense per boe	**$ 0.90**	$ 0.76	$ 0.73

Our D&D rate has increased due to our capital spending substantially weighted to light-oil development and the divestment of non-core properties. D&D and accretion rates were comparable in 2011 and 2010.

We recorded an impairment charge during the fourth quarter of 2012 related to legacy, base natural gas assets in northern British Columbia as a result of lower natural gas prices.

In 2011, we recorded an impairment reversal of $10 million to reflect stronger commodity prices resulting in higher forecast cash flows relating to properties in central Alberta.

Taxes

(millions)	Year ended December 31		
	2012	2011	2010
Deferred tax expense (recovery)	**$63**	$(227)	$(101)

In 2012, we recorded a deferred tax expense primarily due to gains on property dispositions and from unrealized risk management gains.

The deferred tax recovery for the year ended December 31, 2011 includes a $304 million recovery related to the tax rate differential on our conversion from a trust to an E&P company on January 1, 2011. As a corporation, we are subject to income taxes at Canadian corporate tax rates. Under the former trust structure, IFRS required us to tax-effect timing differences in our trust entities at rates applicable to undistributed earnings of a trust being the maximum marginal income tax rate for individuals in the Province of Alberta.

The 2010 amount included a $177 million recovery related to corporate restructuring.

Tax Pools

(millions)	As at December 31 2012	2011	2010
Undepreciated capital cost (UCC)	**$1,155**	$1,085	$1,122
Canadian oil and gas property expense (COGPE)	**24**	1,395	1,562
Canadian development expense (CDE)	**2,713**	2,104	1,494
Canadian exploration expense (CEE)	**348**	294	305
Non-capital losses	**1,963**	2,966	2,481
Other	**21**	31	31
Total	**$6,224**	$7,875	$6,995

Tax pool amounts exclude income deferred in operating partnerships of $616 million in 2012 (2011 – $1,654 million and 2010 – $920 million).

Foreign Exchange

(millions)	Year ended December 31 2012	2011	2010
Unrealized foreign exchange loss (gain)	**$ (32)**	$ 38	$ (82)

We record unrealized foreign exchange gains or losses to translate the U.S., UK and Euro denominated notes and the related accrued interest to Canadian dollars using the exchange rates in effect on the balance sheet date. The unrealized gains during 2012 and 2010 were primarily due to the strengthening of the Canadian dollar relative to the US dollar and the losses during 2011 were primarily due to the weakening of the Canadian dollar relative to the US dollar.

Funds Flow and Net Income

	Year ended December 31 2012	2011	2010
Funds flow [1] (millions)	**$1,248**	$1,537	$1,185
Basic per share	**2.62**	3.29	2.68
Diluted per share	**2.62**	3.29	2.65
Net income (millions)	**174**	638	1,110
Basic per share	**0.37**	1.37	2.51
Diluted per share	**$ 0.37**	$ 1.36	$ 2.48

(1) Funds flow is a non-GAAP measure. See “Calculation of Funds Flow”.

Funds flow in 2012 decreased from 2011 as a result of lower commodity price realizations and disposition activity. Funds flow for 2011 increased from 2010 primarily due to an increase in our weighting of light-oil production and an increase in crude oil prices.

In 2012, net income decreased as lower revenues from the decline in commodity prices and an impairment charge on legacy natural gas properties were partially offset by gains from property dispositions and risk management gains.

For 2011, net income decreased compared to 2010 as significant gains on asset dispositions were recorded in 2010 on the formation of the Cordova Joint Venture and the Peace River Oil Partnership. Net income in 2011 included a $304 million deferred tax recovery related to our conversion from an income trust to a corporate structure.

	Year ended December 31					
	2012		2011		2010	
	per boe	**%**	per boe	%	per boe	%
Oil and natural gas revenues [1]	**$ 55.63**	**100**	$ 60.54	100	$ 50.46	100
Royalties	**(10.07)**	**(18)**	(11.09)	(18)	(9.07)	(18)
Operating expenses [2]	**(17.26)**	**(31)**	(17.40)	(29)	(15.71)	(31)
Transportation	**(0.50)**	**(1)**	(0.49)	(1)	(0.55)	(1)
Net operating income	**27.80**	**50**	31.56	52	25.13	50
General and administrative expenses	**(2.91)**	**(6)**	(2.38)	(4)	(2.41)	(5)
Restructuring	**(0.23)**	**—**	—	—	—	—
Share-based compensation – cash	**(0.14)**	**—**	(0.15)	—	(0.14)	—
Financing [3]	**(3.37)**	**(6)**	(3.20)	(5)	(2.89)	(6)
Funds flow	**21.15**	**38**	25.83	43	19.69	39
Unrealized foreign exchange gain (loss)	**0.54**	**1**	(0.64)	(1)	1.36	3
Share-based compensation	**0.31**	**—**	(1.26)	(2)	(2.51)	(5)
Risk management activities [4]	**2.55**	**5**	0.55	1	0.40	1
Depletion and depreciation	**(25.86)**	**(46)**	(19.45)	(32)	(19.44)	(39)
Accretion	**(0.90)**	**(2)**	(0.76)	(1)	(0.73)	(1)
Gain on dispositions	**6.51**	**12**	2.89	5	18.02	36
Exploration and evaluation	**(0.29)**	**(1)**	(0.25)	(1)	(0.02)	—
Deferred tax recovery (expense)	**(1.07)**	**(2)**	3.80	6	1.70	3
Net income	**$ 2.94**	**5**	$ 10.71	18	$ 18.47	37

(1) Gross revenues include realized gains and losses on commodity contracts.
(2) Operating expenses include realized gains/ losses on electricity swaps.
(3) Financing expenses include realized losses on interest rate swaps.
(4) Risk management activities relate to unrealized gains and losses on derivative instruments.

Drilling

	Year ended December 31			
	2012		2011	
	Gross	**Net**	Gross	Net
Oil	**349**	**263**	457	353
Natural gas	**23**	**19**	53	36
	372	**282**	510	389
Stratigraphic and service	**72**	**32**	89	37
Total	**444**	**314**	599	426
Success rate [1]		**100%**		100%

(1) Success rate is calculated excluding stratigraphic and service wells.

Capital Expenditures

(millions)	Year ended December 31 2012	2011	2010
Land acquisition and retention	**$ 37**	$ 181	$ 102
Drilling and completions	**1,148**	1,217	800
Facilities and well equipping	**675**	521	281
Geological and geophysical	**13**	9	10
Corporate	**16**	25	11
Capital expenditures [1]	**1,889**	1,953	1,204
Joint venture, carried capital	**(137)**	(107)	(17)
Property dispositions, net	**(1,615)**	(266)	(1,306)
Business combinations	**—**	286	139
Total expenditures	**$ 137**	$1,866	$ 20

(1) Capital expenditures include costs related to development capital and Exploration and Evaluation activities.

Our 2012 and 2011 capital programs continued to be directed towards our key light-oil projects, focusing on the Carbonates, Cardium, Spearfish and Viking. During 2012, we completed net property dispositions of non-core properties with combined production of approximately 16,500 barrels of oil equivalent per day. In 2011, we were successful at land sales and acquired strategic lands to complement our existing asset base.

Exploration and evaluation ("E&E") capital expenditures

(millions)	Year ended December 31 2012	2011	2010
E&E capital expenditures	**$228**	$321	$ 58

E&E expenditures include land acquisitions, appraisal activities at our Cordova and Peace River joint ventures and other exploration costs. For 2012, we had a non-cash E&E expense of $17 million (2011 – $15 million and 2010 – $1 million) primarily related to land expiries and minor properties not expected to be continued to the development phase. We also had transfers into Property, Plant and Equipment totalling $16 million (2011 – $14 million and 2010 – nil) and dispositions of $4 million (2011 – $2 million and 2010 – $61 million).

Gain on asset dispositions

(millions)	Year ended December 31 2012	2011	2010
Gain on asset dispositions	**$384**	$172	$1,082

The gains recognized in income during 2012 and 2011 related to property dispositions of non-core assets. We recorded significant gains in 2010 as a result of forming the Peace River Oil Partnership in June 2010 and entering the Cordova Joint Venture in September 2010.

Spartan Exploration Ltd. ("Spartan") business combination

On June 1, 2011, we closed the acquisition of Spartan, a publicly traded oil and gas exploration company with assets primarily located in the Cardium light-oil resource play in central Alberta. The total cost was $166 million, including the assumption of approximately $39 million of debt, with $286 million recorded to property, plant and equipment.

Goodwill

(millions)	Year ended December 31 2012	2011	2010
Balance, beginning and end of year	**$2,020**	$2,020	$2,020

We recorded goodwill on our acquisitions of Petrofund Energy Trust, Canetic Resources Trust and Vault Energy Trust in previous years. We determined there was no goodwill impairment at December 31, 2012 or 2011.

Environmental and Climate Change

The oil and gas industry has a number of environmental risks and hazards and is subject to regulation by all levels of government. Environmental legislation includes, but is not limited to, operational controls, site restoration requirements and restrictions on emissions of various substances produced in association with oil and natural gas operations. Compliance with such legislation could require additional expenditures and a failure to comply may result in fines and penalties which could, in the aggregate and under certain unlikely assumptions, become material.

We are dedicated to reducing the environmental impact from our operations through our environmental programs which include resource conservation, water management, site abandonment/reclamation and CO2 sequestration. Operations are continuously monitored to minimize the environmental impact and capital is allocated to reclamation and other activities to mitigate the impact on the areas in which we operate.

Liquidity and Capital Resources

Capitalization

(millions)	As at December 31 2012	%	2011	%	2010	%
Common shares issued, at market [1]	**$5,176**	**64**	$ 9,517	72	$10,959	78
Bank loans and long-term notes	**2,690**	**33**	3,219	24	2,496	18
Convertible debentures	**—**	**—**	—	—	255	2
Working capital deficiency [2]	**239**	**3**	554	4	303	2
Total enterprise value	**$8,105**	**100**	$13,290	100	$14,013	100

(1) The share price at December 31, 2012 was $10.80 (2011—$20.19 and 2010—$23.84).
(2) Excludes the current portion of risk management, long-term debt, convertible debentures and share-based compensation liability.

Dividends

(millions)	Year ended December 31 2012	2011	2010
Dividends declared	**$ 514**	$ 506	$ 686
Per share	**1.08**	1.08	1.56
Dividends paid [1]	**$ 512**	$ 420	$ 708

(1) Includes amounts funded by the dividend reinvestment plan.

On February 13, 2013, our Board of Directors declared a first quarter 2013 dividend of $0.27 per share to be paid on April 15, 2013 to shareholders of record at the close of business on March 28, 2013. Shareholders who are residents of Canada are advised that this dividend is designated as an “eligible dividend” for Canadian income tax purposes.

The amount of future cash dividends may vary depending on a variety of factors and conditions which can include, but are not limited to, fluctuations in commodity markets, production levels and capital investment plans. Our dividend level could change based on these and other factors and is subject to the approval of our Board of Directors. For further information regarding our dividend policy, including the factors that could affect the amount of quarterly dividend that we pay and the risks relating thereto, see "Dividends and Dividend Policy – Dividend Policy" in our Annual Information Form, which is available on our website at www.pennwest.com, on the SEDAR website at www.sedar.com, and on the SEC website at www.sec.gov.

Liquidity

The Company currently has an unsecured, revolving, syndicated bank facility with an aggregate borrowing limit of $3.0 billion expiring on June 30, 2016. For further details on our debt instruments, please refer to the "Financing" section of this MD&A.

We actively manage our debt capital and consider opportunities to reduce or diversify our debt structure. We contemplate operating and financial risks and take actions as appropriate to limit our exposure to certain risks. We maintain close relationships with our lenders and agents to monitor credit market developments. Strategies aim to increase the likelihood of maintaining our financial flexibility to capture opportunities available in the markets in addition to the continuation of our capital and dividend programs and hence the longer-term execution of our business strategies.

The Company has a number of covenants related to its syndicated bank facility and senior, unsecured notes. On December 31, 2012, the Company was in compliance with all of these financial covenants which consist of the following:

	Limit	December 31, 2012
Senior debt to EBITDA (1)	Less than 3:1	**2.1**
Total debt to EBITDA (1)	Less than 4:1	**2.1**
Senior debt to capitalization	Less than 50%	**23%**
Total debt to capitalization	Less than 55%	**23%**

(1) EBITDA is calculated in accordance with Penn West's lending agreements wherein unrealized risk management gains and losses and impairment provisions are excluded.

All senior, unsecured notes contain change of control provisions whereby if a change of control occurs; the Company may be required to offer to prepay the notes, which the holders have the right to refuse.

Convertible Debentures

We had no convertible debentures outstanding at December 31, 2012 or 2011. During 2011, $248 million of convertible debentures matured and were settled in cash (2010 – nil), $7 million were redeemed and settled in cash (2010 – nil) and none matured and were settled in shares (2010 – $18 million). Of the $255 million of convertible debentures settled in cash during 2011, $224 million were the series "F" debentures which matured in the fourth quarter of 2011.

Financial Instruments

We had the following financial instruments outstanding as at December 31, 2012. Fair values are determined using external counterparty information which is compared to observable market data. We limit our credit risk by executing counterparty risk procedures which include transacting only with institutions within our credit facility or with high credit ratings and by obtaining financial security in certain circumstances.

	Notional volume	Remaining term	Pricing	Fair value (millions)
Crude oil				
WTI Collars	55,000 bbls/d	Jan/13—Dec/13	US$91.55 to $104.42/bbl	$66
Natural gas				
AECO Forwards	125,000 mcf/d	Jan/13—Dec/13	$3.34/mcf	9
AECO Forwards	25,000 mcf/d	Jan/14—Dec/14	$3.85/mcf	2
AECO Collars	25,000 mcf/d	Jan/14–Dec/14	$3.25 to $4.35/mcf	—
Electricity swaps				
Alberta Power Pool	30 MW	Jan/13—Dec/13	$54.60/MWh	1
Alberta Power Pool	20 MW	Jan/13—Dec/13	$56.10/MWh	1
Alberta Power Pool	70 MW	Jan/14—Dec/14	$58.50/MWh	(5)
Alberta Power Pool	10 MW	Jan/14—Dec/15	$58.50/MWh	(1)
Alberta Power Pool	45 MW	Jan/15—Dec/15	$58.28/MWh	(4)
Alberta Power Pool	25 MW	Jan/16—Dec/16	$49.90/MWh	—
Interest rate swaps	$650	Jan/13—Jan/14	2.65%	(10)
Foreign exchange forwards on senior notes				
3 to 15-year initial term	US$641	2014—2022	1.000 CAD/USD	23
Cross currency swaps				
10-year initial term	£57	2018	2.0075 CAD/GBP, 6.95%	(19)
10-year initial term	£20	2019	1.8051 CAD/GBP, 9.15%	(3)
10-year initial term	€10	2019	1.5870 CAD/EUR, 9.22%	(2)
Total				$58

Please refer to our website at www.pennwest.com for details of all financial instruments currently outstanding.

Subsequent to December 31, 2012, we entered into foreign exchange forward contracts on revenue from March 2013 to December 2013 on $153 million per month at an average foreign exchange rate of 1.022 CAD/USD. We also entered into additional natural gas collars on 25,000 mcf per day in 2014 between $3.57 per mcf and $4.00 per mcf.

Additionally, we have subsequently entered into oil differential contracts from March to June 2013 on 4,000 barrels per day. These contracts fix the price of MSW (mixed sweet crudes at Edmonton) at a discount of USD $8.00 per barrel to WTI.

Outlook

This outlook section is included to provide shareholders with information about our expectations as at March 13, 2013 for production and capital expenditures in 2013 and readers are cautioned that the information may not be appropriate for any other purpose. This information constitutes forward-looking information. Readers should note the assumptions, risks and discussion under “Forward-Looking Statements” and are cautioned that numerous factors could potentially impact our capital expenditure levels and production performance for 2013, including our current disposition program.

Our 2013 forecast exploration and development capital is $900 million with an option to layer in up to $300 million of incremental capital later in 2013, subject to external market factors and internal performance. After the divestment activity in 2012, we forecast 2013 average production of between 135,000 and 145,000 boe per day.

There have been no changes to our guidance from our prior forecast, released on February 14, 2013 with our fourth quarter results and filed on SEDAR at www.sedar.com.

Our 2012 annual capital expenditure and production guidance released on November 2, 2012 with our third quarter results were met.

Sensitivity Analysis

Estimated sensitivities to selected key assumptions on funds flow for the 12 months subsequent to this reporting period, including risk management contracts entered to date, are based on forecasted results as discussed in the Outlook above.

		Impact on funds flow	
Change of:	Change	$ millions	$/share
Price per barrel of liquids	$ 1.00	24	0.05
Liquids production	1,000 bbls/day	20	0.04
Price per mcf of natural gas	$ 0.10	5	0.01
Natural gas production	10 mmcf/day	2	—
Effective interest rate	1%	6	0.01
Exchange rate ($US per $CAD)	$ 0.01	12	0.02

Contractual Obligations and Commitments

We are committed to certain payments over the next five calendar years as follows:

(millions)	**2013**	2014	2015	2016	2017	Thereafter
Long-term debt	**$ 5**	$ 60	$251	$968	$242	$ 1,164
Transportation	**24**	17	10	4	1	—
Transportation ($US)	**4**	37	37	33	33	198
Power infrastructure	**29**	14	14	14	14	12
Drilling rigs	**23**	21	17	11	6	—
Purchase obligations (1)	**6**	5	5	1	1	1
Interest obligations	**146**	142	132	105	77	136
Office lease (2)	**62**	56	55	54	52	384
Decommissioning liability (3)	**$100**	$ 95	$ 91	$ 87	$ 82	$ 180

(1) These amounts represent estimated commitments of $13 million for CO2 purchases and $6 million for processing fees related to our interests in the Weyburn Unit.
(2) The future office lease commitments above will be reduced by sublease recoveries totalling $335 million.
(3) These amounts represent the inflated, discounted future reclamation and abandonment costs that are expected to be incurred over the life of the properties.

Our syndicated credit facility is due for renewal on June 30, 2016. If we are not successful in renewing or replacing the facility, we could be required to obtain other facilities including term bank loans. In addition, we have an aggregate of $1.9 billion in senior notes maturing between 2014 and 2025. We continuously monitor our credit metrics and maintain positive working relationships with our lenders, investors and agents.

We are involved in various claims and litigation in the normal course of business and record provisions for claims as required.

Equity Instruments

Common shares issued:	
As at December 31, 2012	479,258,670
Issued on exercise of share rights	139,158
Issued pursuant to dividend reinvestment plan	2,807,458
As at March 13, 2013	482,205,286
Options outstanding:	
As at December 31, 2012	15,737,400
Granted	8,248,100
Forfeited	(1,614,185)
As at March 13, 2013	22,371,315
Share Rights outstanding:	
As at December 31, 2012	291,638
Exercised	(79,518)
Forfeited	(28,059)
As at March 13, 2013	184,061
Restricted Options outstanding (1):	
As at December 31, 2012	10,535,361
Forfeited	(2,361,394)
As at March 13, 2013	8,173,967

(1) Each holder of a Restricted Option holds a Restricted Right and has the option to settle the Restricted Right in cash or common shares upon exercise. Refer to the “Expenses—Share-Based Compensation” section of this MD&A for further details.

Fourth Quarter 2012 Highlights

Key financial and operational results for the fourth quarter were as follows:

	Three months ended December 31		
	2012	2011	% change
Financial			
(millions, except per share amounts)			
Gross revenues [1]	**$ 799**	$ 979	(18)
Funds flow	**295**	437	(33)
Basic per share	**0.62**	0.93	(33)
Diluted per share	**0.62**	0.93	(33)
Net loss	**(53)**	(62)	(15)
Basic per share	**(0.11)**	(0.13)	(15)
Diluted per share	**(0.11)**	(0.13)	(15)
Capital expenditures, net [2]	**(916)**	583	(100)
Dividends			
(millions)			
Dividends paid [3]	**$ 129**	$ 127	2
DRIP	**(31)**	(26)	19
Dividends paid in cash	**$ 98**	$ 101	(3)
Operations			
Daily production			
Light oil and NGL (bbls/d)	**82,224**	90,185	(9)
Heavy oil (bbls/d)	**16,847**	17,886	(6)
Natural gas (mmcf/d)	**329**	364	(10)
Total production (boe/d)	**153,931**	168,801	(9)
Average sales price			
Light oil and NGL (per bbl)	**$ 75.91**	$ 88.76	(15)
Heavy oil (per bbl)	**59.85**	76.88	(22)
Natural gas (per mcf)	**$ 3.28**	$ 3.47	(5)
Netback per boe			
Sales price	**$ 54.10**	$ 63.05	(14)
Risk management gain (loss)	**0.51**	(0.84)	100
Net sales price	**54.61**	62.21	(12)
Royalties	**(10.10)**	(11.47)	(12)
Operating expenses	**(17.16)**	(17.48)	(2)
Transportation	**(0.51)**	(0.48)	6
Netback	**$ 26.84**	$ 32.78	(18)

(1) Gross revenues include realized gains and losses on commodity contracts.
(2) Includes net asset acquisitions/dispositions and excludes business combinations. There are no business combinations in the 2012 period.
(3) Includes dividends paid prior to those reinvested in shares under the dividend reinvestment plan. In 2011, we began paying dividends on a quarterly basis. The last monthly distribution payment as a Trust was declared in December 2010 and paid in January 2011 ($0.09 per unit). Our first quarterly dividend ($0.27 per share) as a corporation was paid in April 2011.

Financial

Gross revenues and funds flow decreased in the fourth quarter of 2012 compared to 2011 primarily due to lower commodity price realizations and asset dispositions.

Net loss was comparable between the fourth quarter of 2012 and 2011 as a decline in revenues from lower commodity prices was offset by unrealized risk management gains in 2012. We recorded an impairment charge during the fourth quarter of 2012 related to legacy, base natural gas assets in northern British Columbia as a result of decreased natural gas prices.

We closed non-core asset dispositions during the fourth quarter for proceeds of approximately $1.3 billion. The proceeds were applied to reduce bank debt.

Our capital activity continued to be focused on our light-oil targets with 31 net oil wells drilled during the fourth quarter of 2012.

Operations

Average production in the fourth quarter of 2012 was 153,931 boe per day after the impact of net asset dispositions and weighted approximately 64 percent to oil and liquids. During the fourth quarter of 2012, we completed net asset dispositions with combined production of approximately 13,000 boe per day.

In the fourth quarter of 2012, WTI crude oil prices averaged US$88.20 per barrel compared to US$92.19 per barrel in the third quarter of 2012 and US$94.02 per barrel for the fourth quarter of 2011. Edmonton light sweet oil traded at a discount of $3.46 per barrel to WTI during the fourth quarter of 2012 (2011 – premium of $1.44 per barrel) compared to a discount of $7.40 per barrel during the third quarter of 2012. In the fourth quarter of 2012, the AECO Monthly Index averaged $3.06 per mcf compared to $2.19 per mcf in the third quarter of 2012 and $3.47 per mcf for the fourth quarter of 2011.

Netbacks were $26.84 per boe compared to $32.78 per boe in the fourth quarter of 2011. The decrease was primarily attributed to lower commodity prices.

Disclosure Controls and Procedures

As of December 31, 2012, an internal evaluation was carried out under the supervision of our President and Chief Executive Officer (the “CEO”) and Executive Vice President and Chief Financial Officer (the “CFO”) of the effectiveness of Penn West’s disclosure controls and procedures as defined in Rule 13a-15 under the US Securities Exchange Act of 1934 (the “Exchange Act”) and as defined in Canada by National Instrument 52-109, Certification of Disclosure in Issuers’ Annual and Interim Filings (“NI 52-109”). Based on that evaluation, the CEO and the CFO concluded that as of December 31, 2012 the disclosure controls and procedures were effective to provide reasonable assurance that the information required to be disclosed in the reports that Penn West files or submits under the Exchange Act or under Canadian securities legislation is recorded, processed, summarized and reported, within the time periods specified in the rules and forms therein.

Internal Control over Financial Reporting ("ICOFR")

We have a team of qualified and experienced staff who continue to maintain our compliance with the applicable regulations regarding internal control over financial reporting ("ICOFR"). As of December 31, 2012, an internal evaluation was carried out under the supervision of our CEO and CFO of the effectiveness of our ICOFR as defined in Rule 13a-15 under the Exchange Act and as defined in Canada by NI 52-109. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, the CEO and the CFO concluded that as of December 31, 2012 our ICOFR was effective. We have certified our ICOFR and obtained auditor attestation of the operating effectiveness of our internal control over financial reporting in conjunction with our 2012 year-end audited consolidated financial statements. All significant financial reporting processes have been documented, assessed, and tested. No changes in our ICOFR were made during the quarter ended December 31, 2012 that have materially affected, or are reasonably likely to materially affect, our ICOFR.

Future Accounting Pronouncements

In May 2011, the International Accounting Standards Board issued the following standards which are not yet effective:

IFRS 9 "Financial Instruments" outlines a new methodology for the recognition and measurement requirements for financial instruments. This new standard will eventually replace IAS 39 "Financial Instruments: Recognition and Measurement". The standard becomes effective for annual periods beginning on or after, January 1, 2015. This standard is still in development; therefore, we cannot assess the impact of this standard at this time.

IFRS 10 "Consolidated Financial Statements" outlines a new methodology to determine whether to consolidate an investee. This new standard becomes effective for annual periods beginning on or after January 1, 2013. We believe the adoption of this standard will have no material impact on our financial statements.

IFRS 11 "Joint Arrangements" outlines the accounting treatment for joint arrangements, notably joint operations which will follow the proportionate consolidation method and joint ventures which will follow the equity accounting method. This new standard becomes effective for annual periods beginning on or after January 1, 2013 and will apply to our interest in the Peace River Oil Partnership. We currently believe that our interest in the Peace River Oil Partnership is appropriately classified as a joint operation; therefore we will continue to proportionately consolidate our interest in the Partnership upon adoption of this standard.

IFRS 12 "Disclosure of Interests in Other Entities" outlines disclosure requirements for interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. These disclosure requirements are required for annual periods beginning on or after January 1, 2013. We are currently assessing the impact of this standard.

IFRS 13 "Fair Value Measurement" defines fair value, provides guidance on measuring fair value and outlines disclosure requirements for fair value measurement. This standard applies when another IFRS standard requires fair value measurements or disclosures, with some exceptions including IFRS 2 "Share based payments" and IAS 17 "Leases". This new standard is applicable for annual periods beginning on or after January 1, 2013. We are currently assessing the impact of this standard.

Off-Balance-Sheet Financing

We have off-balance-sheet financing arrangements consisting of operating leases. The operating lease payments are summarized in the Contractual Obligations and Commitments section.

Critical Accounting Estimates

Our significant accounting policies are detailed in Note 3 to our audited consolidated financial statements. In the determination of financial results, we must make certain critical accounting estimates as follows:

Depletion and Impairments

Costs of developing oil and natural gas reserves are capitalized and depleted against associated oil and natural gas production using the unit-of-production method based on the estimated proved plus probable reserves with forecast commodity pricing.

All of our reserves were evaluated or audited by GLJ Petroleum Consultants Ltd. ("GLJ") and Sproule Associates Limited ("SAL"), both independent, qualified reserve evaluation engineering firms. Our reserves are determined in compliance with National Instrument 51-101. The evaluation of oil and natural gas reserves is, by its nature, based on complex extrapolations and models as well as other significant engineering, reservoir, capital, pricing and cost assumptions. Reserve estimates are a key component in the calculation of depletion and are an important component in determining the recoverable amount in the impairment test. The determination of the recoverable amount involves estimating the higher of an asset's fair value less costs to sell or its value-in-use, the latter of which is based on its discounted future cash flows using an applicable discount rate. To the extent that the recoverable amount, which could be based in part on our reserves, is less than the carrying amount of property, plant and equipment, a write-down against income must be made. We recorded a $277 million impairment related to certain properties in northern British Columbia, primarily due to weak natural gas forward prices on December 31, 2012. No impairment existed at December 31, 2011.

Decommissioning Liability

The decommissioning liability is the present value of our future statutory, contractual, legal or constructive obligations to retire long-lived assets. The liability is recorded on the balance sheet with a corresponding increase to the carrying amount of the related asset. The recorded liability increases over time to its future liability amount through accretion charges to income. Revisions to the estimated amount or timing of the obligations are reflected as increases or decreases to the recorded decommissioning liability. Actual decommissioning expenditures are charged to the liability to the extent of the then-recorded liability. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset. Note 10 to our audited consolidated financial statements details the impact of these accounting standards.

Financial Instruments

Financial instruments included in the balance sheets consist of accounts receivable, fair values of derivative financial instruments, current liabilities and long-term debt. Except for the senior notes, the fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of the instruments, the mark-to-market values recorded for the financial instruments and the market rate of interest applicable to the bank debt. The estimated fair value of the senior notes is disclosed in Note 9 to our audited consolidated financial statements.

Our revenues from the sale of crude oil, natural gas liquids and natural gas are directly impacted by changes to the underlying commodity prices. To ensure that funds flows are sufficient to fund planned capital programs and dividends, financial instruments including collars may be utilized from time to time. Collars ensure that commodity prices realized will fall into a contracted range for a contracted sales volume.

Substantially all of our accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risk. We may, from time to time, use various types of financial instruments to reduce our exposure to fluctuating oil and natural gas prices, electricity costs, exchange rates and interest rates. The use of these financial instruments exposes us to credit risks associated with the possible non-performance of counterparties to the derivative contracts. We limit this risk by executing counterparty risk procedures which include transacting only with financial institutions who are members of our credit facility or those with high credit ratings as well as obtaining security in certain circumstances.

Goodwill

Goodwill must be recorded on a business combination when the total purchase consideration exceeds the fair value of the net identifiable assets and liabilities of the acquired entity. The goodwill balance is not amortized; however, it must be assessed for impairment at least annually. We determined there was no goodwill impairment at December 31, 2012 and 2011.

Deferred Tax

Deferred taxes are recorded based on the liability method of accounting whereby temporary differences are calculated assuming financial assets and liabilities will be settled at their carrying amount. Deferred taxes are computed on temporary differences using substantively enacted income tax rates expected to apply when future income tax assets and liabilities are realized or settled.

Forward-Looking Statements

In the interest of providing our securityholders and potential investors with information regarding Penn West, including management's assessment of our future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "continue", "estimate", "expect", "forecast", "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 contains forward-looking statements pertaining to, without limitation, the following: under the heading "Business Strategy", among other things, our intent to continue to provide our shareholders a meaningful dividend while focusing on improving capital efficiencies and production reliability, that in 2013 exploration and development capital will be $900 million with an option to layer in up to $300 million of incremental capital later in 2013 subject to external market factors, and our intent to keep our business strategy centered on realizing the value inherent in our extensive light-oil weighted asset base for the benefit of our shareholders; under the heading "Business Environment", that geopolitical concerns related to Syria and Iran will persist and are expected to provide support to world oil prices in 2013; under the heading "Performance Indicators", among other things, the focus of our 2013 capital program on improving capital efficiencies by allocating capital to areas we have significantly de-risked, where we have realized cost reductions, and where we have infrastructure capacity, our plan in 2013 to continue the rotation of our asset portfolio through the disposition of non-core properties and investment in our light-oil resources, and our belief that our strategies will achieve a balance that provides our shareholders with a meaningful dividend as we continue to concentrate our asset base for oil growth; under "Results of Operations", among other things, our intent to continue to focus our capital activity in 2013 on light-oil and our expectation that this should increase our weighting to liquids; under the heading "Environmental and Climate Change", among other things, our intent to reduce the environmental impact from our operations through our environmental programs; under "Liquidity and Capital Resources", our expectation that our strategies will increase the likelihood of maintaining our financial flexibility to capture opportunities available in the markets in addition to the continuation of our capital and dividend programs and hence the longer-term execution of our business strategies; under the heading "Outlook", among other things, our expectation that in 2013 exploration and development capital will be $900 million with an option to layer in up to $300 million of incremental capital later in 2013 subject to external market factors and internal performance and our forecast 2013 average production of between 135,000 and 145,000 boe per day; and certain disclosures contained under the heading "Sensitivity Analysis" relating to our estimated sensitivities to certain key assumptions on our future funds flow.

With respect to forward-looking statements contained in this document, we have made assumptions regarding, among other things: 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 prices; future capital expenditure levels; future crude oil, natural gas liquids and natural gas production levels; that we will be able to successfully dispose of certain non-core assets as expected; drilling results; future exchange rates and interest rates; the amount of future cash dividends that we intend to pay and the level of participation in our dividend reinvestment plan; 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; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and exploitation activities. In addition, many of the forward-looking statements contained 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 under the headings “Outlook” and “Sensitivity Analysis”.

Although we believe that the expectations reflected in the forward-looking statements contained 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 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 impact of weather conditions on seasonal demand and ability to execute capital programs; 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; geological, technical, drilling and processing problems; general economic and political conditions in Canada, the U.S. and globally; industry conditions, including fluctuations in the price of oil and natural gas, price differentials for crude oil produced in Canada as compared to other markets and transportation restrictions; royalties payable in respect of our oil and natural gas production and changes thereto; 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 wild fires and flooding; failure to obtain industry partner and other third-party consents and approvals when required; stock market volatility and market valuations; OPEC’s ability 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; the need to obtain required approvals from regulatory authorities from time to time; failure to realize the anticipated benefits of dispositions, acquisitions, joint ventures and partnerships, including the completed dispositions, acquisitions, joint ventures and partnerships discussed herein; changes in tax and other laws that affect us and our securityholders; changes in government royalty frameworks; failure to complete disposition of non-core assets as expected; uncertainty of obtaining required approvals for acquisitions, dispositions and mergers; the potential failure of counterparties to honour their contractual obligations; and the other factors described in our public filings (including our Annual Information Form) 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 in this document speak only as of the date of this document. Except as expressly required by applicable securities laws, we do 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 in this document are expressly qualified by this cautionary statement.

Additional Information

Additional information relating to Penn West including Penn West's Annual Information Form, is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

Exhibit 99.3

MANAGEMENT'S REPORT

The consolidated financial statements as at and for the years ended December 31, 2012 and December 31, 2011 of Penn West Petroleum Ltd. were prepared by management in accordance with accounting principles generally accepted in Canada. In preparing the consolidated financial statements, management has made estimates because a precise determination of certain assets and liabilities is dependent on future events. The financial and operating information presented in this report is consistent with that shown in the consolidated financial statements.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of relevant, reliable and timely financial records for the preparation of statements. An internal evaluation was carried out under the supervision of our CEO and CFO of the effectiveness of our internal control over financial reporting as defined in Rule 13a-15 under the Exchange Act and as defined in Canada by NI 52-109. The assessment was based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, the CEO and the CFO concluded that as of December 31, 2012 our internal control over financial reporting was effective.

The consolidated financial statements have been examined by the external auditors and approved by the Board of Directors. The Board of Directors' financial statement related responsibilities are fulfilled through the Audit Committee. The Audit Committee is composed entirely of independent directors. The Audit Committee recommends appointment of the external auditors to the Board of Directors, ensures their independence, and approves their fees. The Audit Committee meets regularly with management and the external auditors to discuss reporting and control issues and to ensure each party is properly discharging its responsibilities. The external auditors have full and unrestricted access to the Audit Committee to discuss their audit and their related findings as to the integrity of the financial reporting process.

(signed) *"Murray R. Nunns"*	(signed) *"Todd H. Takeyasu"*
Murray R. Nunns President & CEO	Todd H. Takeyasu Executive Vice President & CFO

March 13, 2013

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Penn West Petroleum Ltd.

We have audited the accompanying consolidated financial statements of Penn West Petroleum Ltd., which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011, the consolidated statements of income, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Penn West Petroleum Ltd. as at December 31, 2012 and December 31, 2011, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matters

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Penn West Petroleum Ltd.'s internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 13, 2013 expressed an unmodified (unqualified) opinion on the effectiveness of Penn West Petroleum Ltd.'s internal control over financial reporting.

(signed) *"KPMG LLP"*

KPMG LLP
Chartered Accountants
Calgary, Canada
March 13, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Penn West Petroleum Ltd.

We have audited Penn West Petroleum Ltd.'s internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in "Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission".

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets as at December 31, 2012 and December 31, 2011, the consolidated statements of income, changes in shareholders' equity and cash flows for the years then ended, and our report dated March 13, 2013 expressed an unmodified (unqualified) opinion on those consolidated financial statements.

(signed) *"KPMG LLP"*

KPMG LLP
Chartered Accountants
Calgary, Canada
March 13, 2013

Penn West Petroleum Ltd.
Consolidated Balance Sheets

(CAD millions)	Note	December 31, 2012	December 31, 2011
Assets			
Current			
Accounts receivable	4	**$ 364**	$ 486
Other	4	**79**	104
Deferred funding assets	5	**187**	236
Risk management	11	**76**	39
		706	865
Non-current			
Deferred funding assets	5	**238**	360
Exploration and evaluation assets	6	**609**	418
Property, plant and equipment	7	**10,892**	11,893
Goodwill	8	**2,020**	2,020
Risk management	11	**26**	28
		13,785	14,719
Total assets		**$ 14,491**	$ 15,584
Liabilities and Shareholders' Equity			
Current			
Accounts payable and accrued liabilities	4	**$ 764**	$ 1,108
Dividends payable	15	**129**	127
Current portion of long-term debt	9	**5**	—
Risk management	11	**9**	114
		907	1,349
Non-current			
Long-term debt	9	**2,685**	3,219
Decommissioning liability	10	**635**	607
Risk management	11	**35**	46
Deferred tax liability	12	**1,350**	1,287
Other non-current liabilities	14	**5**	9
		5,617	6,517
Shareholders' equity			
Shareholders' capital	13	**8,985**	8,840
Other reserves	13	**97**	95
Retained earnings (deficit)		**(208)**	132
		8,874	9,067
Total liabilities and shareholders' equity		**$ 14,491**	$ 15,584

Subsequent events (Notes 11, 14 and 15)
Commitments and contingencies (Note 20)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors of Penn West Petroleum Ltd.:

(signed) *"John A. Brussa"* (signed) *"James C. Smith"*

John A. Brussa, Chairman
James C. Smith, Director

Penn West Petroleum Ltd.
Consolidated Statements of Income

(CAD millions, except per share amounts)	Note	Year ended December 31 2012	2011
Oil and natural gas sales		**$3,235**	$3,667
Royalties		**(595)**	(661)
		2,640	3,006
Risk management gain (loss)			
Realized		**48**	(63)
Unrealized	11	**156**	8
		2,844	2,951
Expenses			
Operating		**1,019**	1,036
Transportation		**29**	29
General and administrative		**172**	142
Restructuring		**13**	—
Share-based compensation	14	**(10)**	84
Depletion, depreciation and impairment	7	**1,525**	1,158
Gain on dispositions		**(384)**	(172)
Exploration and evaluation	6	**17**	15
Unrealized risk management loss (gain)	11	**5**	(25)
Unrealized foreign exchange loss (gain)		**(32)**	38
Financing	9	**199**	190
Accretion	10	**54**	45
		2,607	2,540
Income before taxes		**237**	411
Deferred tax expense (recovery)	12	**63**	(227)
Net and comprehensive income		**$ 174**	$ 638
Net income per share			
Basic	16	**$ 0.37**	$ 1.37
Diluted	16	**$ 0.37**	$ 1.36
Weighted average shares outstanding (millions)			
Basic	16	**475.6**	467.2
Diluted	16	**475.8**	467.4

See accompanying notes to the consolidated financial statements.

Penn West Petroleum Ltd.
Consolidated Statements of Cash Flows

(CAD millions)	Note	Year ended December 31 2012	2011
Operating activities			
Net income		**$ 174**	$ 638
Depletion, depreciation and impairment		**1,525**	1,158
Gain on dispositions		**(384)**	(172)
Exploration and evaluation		**17**	15
Accretion		**54**	45
Deferred tax expense (recovery)		**63**	(227)
Share-based compensation		**(18)**	75
Unrealized risk management gain		**(151)**	(33)
Unrealized foreign exchange loss (gain)		**(32)**	38
Decommissioning expenditures	10	**(92)**	(81)
Change in non-cash working capital	17	**37**	(49)
		1,193	1,407
Investing activities			
Capital expenditures		**(1,752)**	(1,846)
Property dispositions (acquisitions), net		**1,615**	266
Business combinations		**—**	(166)
Change in non-cash working capital	17	**(168)**	113
		(305)	(1,633)
Financing activities			
Increase (decrease) in bank loan		**(496)**	475
Proceeds from issuance of notes		**—**	212
Repayment of acquired credit facilities		**—**	(39)
Issue of equity		**3**	161
Dividends and distributions paid		**(395)**	(328)
Settlement of convertible debentures		**—**	(255)
		(888)	226
Change in cash		**—**	—
Cash, beginning of year		**—**	—
Cash, end of year		**$ —**	$ —

See accompanying notes to the consolidated financial statements.

Penn West Petroleum Ltd.
Statements of Changes in Shareholders' Equity

(CAD millions)	Note	Shareholders' Capital	Other Reserves	Deficit	Total
Balance at January 1, 2012		$ 8,840	$ 95	$ 132	$9,067
Net and comprehensive income		—	—	174	174
Share-based compensation	14	—	27	—	27
Issued on exercise of options and share rights	13	28	(25)	—	3
Issued to dividend reinvestment plan	13	117	—	—	117
Dividends declared		—	—	(514)	(514)
Balance at December 31, 2012		**$ 8,985**	**$ 97**	**$(208)**	**$8,874**

(CAD millions)	Note	Shareholders' Capital	Other Reserves	Retained Earnings	Total
Balance at January 1, 2011		$ 9,170	$ —	$ (610)	$8,560
Elimination of deficit	13	(610)	—	610	—
Net and comprehensive income		—	—	638	638
Implementation of Option Plan and CSRIP	14	—	81	—	81
Share-based compensation	14	—	41	—	41
Issued on exercise of options and share rights	13	188	(27)	—	161
Issued to dividend reinvestment plan	13	92	—	—	92
Dividends declared		—	—	(506)	(506)
Balance at December 31, 2011		$ 8,840	$ 95	$ 132	$9,067

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements
(All tabular amounts are in CAD millions except numbers of common shares, per share amounts, percentages and various figures in Note 11)

1. Structure of Penn West

Penn West Petroleum Ltd. ("Penn West" or the "Company") is a senior exploration and production company and is governed by the laws of the Province of Alberta, Canada. The business of Penn West is to explore for, develop and hold interests in petroleum and natural gas properties directly and through investments in securities of subsidiaries holding interests in oil and natural gas properties and related production infrastructure. Penn West owns the petroleum and natural gas assets or 100 percent of the equity, directly or indirectly, of the entities that carry on the remainder of the oil and natural gas business of Penn West, except for an unincorporated joint arrangement (the "Peace River Oil Partnership") in which Penn West's wholly owned subsidiaries hold a 55 percent interest.

On January 1, 2011, Penn West completed its plan of arrangement and converted from an income trust to a conventional corporation now operating under the trade name of Penn West Exploration.

2. Basis of presentation and statement of compliance

a) Statement of Compliance

These annual consolidated financial statements are prepared in compliance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board.

The annual consolidated financial statements have been prepared on a historical cost basis, except risk management assets and liabilities which are recorded at fair value as discussed in Note 11.

The annual consolidated financial statements were approved for issuance by the Board of Directors on March 13, 2013.

b) Basis of Presentation

The annual consolidated financial statements include the accounts of Penn West, its wholly owned subsidiaries and its proportionate interest in partnerships. Results from acquired properties are included in Penn West's reported results subsequent to the closing date and results from properties sold are included until the closing date.

All intercompany balances, transactions, income and expenses are eliminated on consolidation.

3. Significant accounting policies

a) Critical accounting judgments and key estimates

The preparation of the consolidated financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the recorded amounts of assets and liabilities, disclosure of any contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses for the period. These and other estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in these estimates could be material.

Management also makes judgments while applying accounting policies that could affect amounts recorded in its consolidated financial statements. Significant judgments include the identification of cash generating units ("CGUs") for impairment testing purposes and the application of the accounting policy for exploration and evaluation ("E&E") assets in determining whether the assets are technically feasible and commercially viable.

The following are the estimates that management has made in applying the Company's accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements.

i) Reserve estimates

Commercial petroleum reserves are determined based on estimates of petroleum-in-place, recovery factors and future oil and natural gas prices and costs. Penn West engages independent qualified reserve evaluators to audit or evaluate all of the Company's oil and natural gas reserves at each year-end.

Reserve adjustments are made annually based on actual oil and natural gas volumes produced, the results from capital programs, revisions to previous estimates, new discoveries and acquisitions and dispositions made during the year and the effect of changes in forecast future crude oil and natural gas prices. There are a number of estimates and assumptions that affect the process of evaluating reserves.

Proved reserves are the estimated quantities of crude oil, natural gas and natural gas liquids determined to be economically recoverable under existing economic and operating conditions with a high degree of certainty (at least 90 percent) those quantities will be exceeded. Proved plus probable reserves are the estimated quantities of crude oil, natural gas and natural gas liquids determined to be economically recoverable under existing economic and operating conditions with a 50 percent certainty those quantities will or will not be exceeded. Penn West reports production and reserve quantities in accordance with Canadian practices and specifically in accordance with "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101").

The estimate of proved plus probable reserves is an essential part of the depletion calculation, the impairment test and hence the recorded amount of oil and gas assets.

Penn West cautions users of this information that the process of estimating crude oil and natural gas reserves is subject to a level of uncertainty. The reserves are based on current and forecast economic and operating conditions; therefore, changes can be made to future assessments as a result of a number of factors, which can include commodity prices, new technology, changing economic conditions, future reservoir performance and forecast development activity.

ii) Recoverability of asset carrying values

Penn West assesses its property, plant and equipment ("PP&E") and goodwill for impairment by comparing the carrying amount to the recoverable amount of the underlying assets. The determination of the recoverable amount involves estimating the higher of an asset's fair value less costs to sell or its value-in-use, the latter of which is based on its discounted future cash flows using an applicable discount rate. Future cash flows are calculated based on estimates of future commodity prices and inflation and are discounted based on management's current assessment of market conditions.

iii) Recoverability of exploration and evaluation assets

Exploration and Evaluation ("E&E") assets are assessed for impairment by comparing the carrying amount to the recoverable amount. The assessment of the recoverable amount involves a number of assumptions, including the timing/likelihood/amount of commercial production, further resource assessment plans, and future revenue/costs expected from the asset, if any.

iv) Decommissioning liability

Penn West recognizes a provision for future abandonment activities in the consolidated financial statements at the net present value of the estimated future expenditures required to settle the estimated future obligation at the balance sheet date. The measurement of the decommissioning liability involves the use of estimates and assumptions including the discount rate, the amount and expected timing of future abandonment costs and the inflation rate related thereto. The estimates were made by management and external consultants considering current costs, technology and enacted legislation.

v) Fair value calculation on share-based payments

The fair value of share-based payments is calculated using a Black-Scholes or a Binomial Lattice option-pricing model, depending on the characteristics of the share-based payment. There are a number of estimates used in the calculation such as the expected future forfeiture rate, expected option life and the future price volatility of the underlying security all of which can vary from expectations. The factors applied in the calculation are management's estimates based on historical information and future forecasts.

vi) Fair value of risk management contracts

Penn West records risk management contracts at fair value with changes in fair value recognized in income. The fair values are determined using external counterparty information which is compared to observable market data.

vii) Taxation

The calculation of deferred income taxes is based on a number of assumptions including estimating the future periods in which temporary differences and other tax credits will reverse and the general assumption that substantively enacted future tax rates at the balance sheet date will be in effect when differences reverse.

b) Business combinations

Penn West uses the acquisition method to account for business combinations. The net identifiable assets and liabilities acquired in transactions are generally measured at their fair value on the acquisition date. The acquisition date is the closing date of the business combination. Acquisition costs incurred by Penn West to complete a business combination are expensed in the period incurred except for costs related to the issue of any debt or equity securities which are recognized based on the nature of the related instrument.

Revisions may be made to the initial recognized amounts determined during the measurement period which shall not exceed one year after the close date of the acquisition.

c) Goodwill

Penn West recognizes goodwill on a business combination when the total purchase consideration exceeds the net identifiable assets acquired and liabilities assumed of the acquired entity. Following initial recognition, goodwill is recognized at cost less any accumulated impairment losses.

Goodwill is not amortized and the carrying amount is assessed for impairment on an annual basis on December 31, or more frequently if circumstances arise that indicate impairment may have occurred. To test for impairment, goodwill is assessed at a consolidated level. If the recoverable amount is less than the carrying amount, an impairment loss is recorded and allocated to the carrying value of goodwill. The determination of the recoverable amount involves estimating the higher of an asset's fair value less costs to sell or its value-in-use. Goodwill impairment losses are not reversed in subsequent periods.

d) Revenue

Penn West generally recognizes oil and natural gas revenue when title passes from Penn West to the purchaser or, in the case of services, as contracted services are performed.

Revenue is measured at the fair value of the consideration received or receivable. Revenue from the sale of crude oil, natural gas and natural gas liquids (prior to deduction of transportation costs) is recognized when all the following conditions have been satisfied:

- The significant risks and rewards of ownership of the goods have been transferred to the buyer;
- There is no continuing managerial involvement to the degree usually associated with ownership or effective control over the goods sold;
- The amount of revenue can be reliably measured;
- It is probable that the economic benefits associated with the transaction will flow to Penn West; and
- The costs incurred or to be incurred in respect of the transaction can be reliably measured.

e) Joint arrangements

The consolidated financial statements include Penn West's proportionate share of jointly controlled assets and liabilities and its proportionate share of the revenue, royalties and operating costs. A significant portion of Penn West's exploration and development activities are conducted jointly with others and involve jointly controlled assets. Under such arrangements, Penn West has the exclusive rights to its proportionate interest in the assets and the economic benefits generated from its share of the assets. Income from the sale or use of Penn West's interest in jointly controlled assets and its share of expenses is recognized when it is probable that the economic benefits associated with the transactions will flow to/from Penn West and the amounts can be reliably measured.

The Peace River Oil Partnership is accounted for using the proportionate consolidation method with Penn West recognizing its 55 percent share of revenues, expenses, assets and liabilities.

f) Transportation expense

Transportation costs are paid by Penn West for the shipping of natural gas, crude oil and natural gas liquids from the wellhead to the point of title transfer to buyers. These costs are recognized when services are received.

g) Foreign currency translation

Penn West and each of its subsidiaries use the Canadian dollar as their functional currency. Monetary items, such as accounts receivable and long-term debt, are translated to Canadian dollars at the rate of exchange in effect at the balance sheet date. Non-monetary items, such as PP&E, are translated to Canadian dollars at the rate of exchange in effect when the transactions occurred. Revenues and expenses denominated in foreign currencies are translated at the exchange rate on the date of the transaction. Foreign exchange gains or losses on translation are included in income.

h) E&E

i) Measurement and recognition

E&E assets are initially measured at cost. Items included in E&E primarily relate to exploratory drilling, geological & geophysical activities, acquisition of mineral rights and technical studies. These expenditures are classified as E&E assets until the technical feasibility and commercial viability of extracting oil and natural gas from the assets has been determined.

ii) Transfer to PP&E

E&E costs are transferred to PP&E when proved reserves have been assigned to the asset. If proved reserves will not be established through the completion of E&E activities and there are no plans for development activity in a field, the E&E assets are considered impaired and the amounts are charged to income as E&E expense.

iii) Pre-license costs

Pre-license expenditures incurred before Penn West has obtained the legal rights to explore for hydrocarbons in a specific area are expensed.

iv) Impairment

E&E assets are tested for impairment when facts or circumstances indicate that a possible impairment may exist and prior to their reclassification to PP&E. E&E impairment losses may be reversed in subsequent periods.

i) PP&E

i) Measurement and recognition

Capital expenditures are recognized as PP&E when it is probable that future economic benefits associated with the item will flow to Penn West and the cost can be reliably measured. PP&E includes capital expenditures incurred in the development phases, acquisition and disposition of PP&E, costs transferred from E&E and additions to the decommissioning liability.

Oil & Gas properties are included in PP&E at cost, less accumulated depletion and depreciation and any impairment losses. The cost of a fixed asset includes costs incurred initially to acquire or construct the item and betterment costs.

ii) Depletion and Depreciation

Except for components with a useful life shorter than the reserve life of the associated property, resource properties are depleted using the unit-of-production method based on production volumes before royalties in relation to total proved plus probable reserves. Natural gas volumes are converted to equivalent oil volumes based upon the relative energy content of six thousand cubic feet of natural gas to one barrel of oil. In determining its depletion base, Penn West includes estimated future costs to develop proved plus probable reserves and excludes estimated equipment salvage values and the cost of E&E assets. Changes to reserve estimates are included in the depletion calculation prospectively.

Components of PP&E that are not depleted using the unit-of-production method are depreciated on a straight-line basis over their useful life. The Turnaround component has an estimated useful life of three to five years and the Corporate Asset component has an estimated useful life of 10 years.

iii) Derecognition

The carrying amount of an item of PP&E is derecognized when no future economic benefits are expected from its use or upon sale to a third party. The gain or loss arising from derecognition is included in income and is measured as the difference between the net proceeds, if any, and the carrying amount of the asset.

iv) Major maintenance and repairs

Ongoing costs to maintain properties are generally expensed as incurred. These costs include the cost of labour, consumables and small parts. The costs of material replacement parts, turnarounds and major inspections are capitalized provided it is probable that future economic benefits in excess of cost will be realized and such benefits are expected to extend beyond the current operating period. The carrying amount of a replaced part is derecognized in accordance with our derecognition policies.

v) Impairment

Penn West reviews oil and gas properties for circumstances that indicate its assets may be impaired at the end of each reporting period. These indicators can be internal (i.e. reserve changes) or external (i.e. market conditions) in nature. If an indication of impairment exists, Penn West completes an impairment test which compares the estimated recoverable amount to its carrying value. The estimated recoverable amount is defined under IAS 36 (“Impairment of Assets”) as the higher of an asset’s or Cash Generating Unit’s (“CGU”) fair value less costs to sell and its value-in-use.

Where the recoverable amount is less than the carrying amount, the asset or CGU is deemed to be impaired. Impairment losses identified for a CGU are allocated on a pro rata basis to the assets within the CGU. The impairment loss is recognized as an expense in income.

Value-in-use is computed as the present value of future cash flows expected to be derived from production. Present values are calculated using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Under the fair value less cost to sell method the recoverable amount is determined using various factors, which can include external factors such as observable market conditions and comparable transactions and internal factors such as discounted cash flows related to resource studies and future development plans.

Impairment losses related to PP&E can be reversed in future periods if the estimated recoverable amount of the asset subsequently exceeds the carrying value. The impairment recovery is limited to a maximum of the estimated depreciated historical cost if the impairment had not been recognized. The reversal of the impairment loss is recognized in depletion, depreciation and impairment.

vi) Other Property, Plant and Equipment

Penn West’s corporate assets include computer hardware and software, office furniture, buildings and leasehold improvements and are depreciated on a straight-line basis over their useful lives. Corporate assets are tested for impairment separately from oil and gas assets.

j) Share-based payments

The fair value of options granted under the Stock Option Plan (the "Option Plan") is recognized as compensation expense with a corresponding increase to other reserves over the term of the options based on a graded vesting schedule. Penn West measures the fair value of options granted under the Option Plan at the grant date using a Black-Scholes option-pricing model. The fair value is based on market prices and considers the terms and conditions of the share options granted.

Effective January 1, 2011, Penn West revised its Trust Unit Rights Incentive Plan ("TURIP"), to become the Common Share Rights Incentive Plan ("CSRIP"), and implemented the Option Plan. Trust unit right holders under the former TURIP were given the choice to elect to receive one Restricted Option and one Restricted Right in exchange for each outstanding "in-the-money" trust unit right on the effective date. As option holders who made this election have the choice to settle the Restricted Right in cash or common shares upon exercise, the amount of the related obligation is classified as a liability. Both the Restricted Option and the Restricted Right are measured using a Black-Scholes option-pricing model and are expensed over the expected vesting period of the award.

Trust unit right holders who chose not to make the election or held trust unit rights that were "out-of-the-money" on the effective date received one common share right ("Share Right") in exchange for each trust unit right. Share Rights are measured using a Binomial Lattice option-pricing model on the date of issuance and are classified as equity awards. The fair value of the Share Rights is expensed over their expected vesting period.

Penn West has a Long-Term Retention and Incentive Plan ("LTRIP"). Compensation expense related to the plan is based on a fair value calculation on each reporting date using the awards outstanding and Penn West's share price from the Toronto Stock Exchange ("TSX") on each balance sheet date. The fair value of the awards is expensed over the vesting period based on a graded vesting schedule. Subsequent increases and decreases in the underlying share price results in increases and decreases, respectively, to the accrued obligation until settlement.

Penn West has a Deferred Share Unit Plan ("DSU"), which allows Penn West to grant DSUs in lieu of cash compensation to non-executive directors providing a right to receive, upon retirement, a cash payment based on the volume-weighted-average trading price of the common shares on the TSX for the five trading days immediately prior to the day of payment. Compensation expense related to the plan is based on a fair value calculation on each reporting date using the awards outstanding and Penn West's share price from the Toronto Stock Exchange ("TSX") on each balance sheet date. Management directors are not eligible to participate in the DSU Plan.

k) Provisions

i) General

Provisions are recognized based on an estimate of expenditures required to settle present obligations at the end of the reporting period. The provision is risk adjusted to take into account any uncertainties. When the effect of the time value of money is material, the amount of a provision is calculated as the present value of the future expenditures required to settle the obligations. The discount rate reflects the current assessment of the time value of money and risks specific to the liability when those risks have not already been reflected as an adjustment to future cash flows.

ii) Decommissioning liability

The decommissioning liability is the present value of Penn West's future costs of obligations for property abandonment and site restoration. The liability is recognized on the balance sheet with a corresponding increase to the carrying amount of the related asset. The recorded liability increases over time to its future amount through accretion charges to income. Revisions to the estimated amount or timing of the obligations are reflected prospectively as increases or decreases to the recorded liability and the related asset. Actual decommissioning expenditures, up to the recorded liability at the time, are charged to the liability as the costs are incurred. Amounts capitalized to the related assets are amortized to income consistent with the depletion or depreciation of the underlying asset.

l) Leases

A lease is classified as an operating lease if it does not transfer substantially all of the risks and rewards incidental to ownership of the related asset to the lessee. Operating lease payments are expensed on a straight-line basis over the life of the lease.

m) Share capital

Common shares are classified as equity. Share issue costs are recorded in shareholder's equity, net of applicable taxes. Dividends are paid at the discretion of the Board of Directors and are deducted from retained earnings.

If issued, preferred shares would be classified as equity and could be issued in one or more series.

n) Earnings per share

Earnings per share is calculated by dividing net income or loss attributable to the shareholders by the weighted average number of common shares outstanding during the period. Penn West computes the dilutive impact of equity instruments other than common shares assuming the proceeds received from the exercise of in-the-money share options are used to purchase common shares at average market prices.

o) Taxation

Income taxes are based on taxable income in a taxation year. Taxable income normally differs from income reported in the consolidated statement of income as it excludes items of income or expense that are taxable or deductible in other years or are not taxable or deductible for income tax purposes.

Penn West uses the liability method of accounting for deferred income taxes. Temporary differences are calculated assuming that the financial assets and liabilities will be settled at their carrying amount. Deferred income taxes are computed on temporary differences using substantively enacted income tax rates expected to apply when deferred income tax assets and liabilities are realized or settled.

p) Financial instruments

Financial instruments are measured at fair value and recorded on the balance sheet upon initial recognition of an instrument. Subsequent measurement and changes in fair value will depend on initial classification, as follows:

- Fair value through profit or loss financial assets and liabilities and derivative instruments classified as held for trading or designated as fair value through profit or loss are measured at fair value and subsequent changes in fair value are recognized in income;
- Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market are initially measured at fair value with subsequent changes at amortized cost;
- Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in equity until the instrument or a portion thereof is derecognized or impaired at which time the amounts would be recognized in income;
- Held to maturity financial assets and loans and receivables are initially measured at fair value with subsequent measurement at amortized cost using the effective interest method. The effective interest method calculates the amortized cost of a financial asset and allocates interest income or expense over the applicable period. The rate used discounts the estimated future cash flows over either the expected life of the financial asset or liability or a shorter time-frame if it is deemed appropriate; and
- Other financial liabilities are initially measured at fair value with subsequent changes to fair value measured at amortized cost.

Penn West's current classifications are as follows:

- Cash and cash equivalents and accounts receivable are designated as loans and receivables;
- Accounts payable and accrued liabilities, dividends payable and long-term debt are designated as other financial liabilities; and
- Risk management contracts are derivative financial instruments measured at fair value through profit or loss.

Penn West assesses each financial instrument, except those valued at fair value through profit or loss, for impairment at the reporting date and records the gain or loss in income during the period.

q) Embedded derivatives

An embedded derivative is a component of a contract that affects the terms of another factor, for example, rent costs that fluctuate with oil prices. These "hybrid" contracts are considered to consist of a "host" contract plus an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative if the following conditions are met:

- The economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract;
- The embedded item, itself, meets the definition of a derivative; and
- The hybrid contract is not measured at fair value or designated as held for trading.

At December 31, 2012 and 2011, Penn West had no material embedded derivatives.

r) Compound instruments

Components of compound instruments are classified separately as financial liabilities and equity in accordance with the substance of the contractual arrangement. At the issue date, the fair value of the liability component is estimated using the prevailing market interest rate for a similar non-convertible instrument. This amount is recorded as a liability based on amortized cost until the instrument is converted or the instrument matures. The equity component is determined by deducting the liability component from the total fair value of the compound instrument and is recognized as equity, net of income tax effects, with no subsequent re-measurement.

At December 31, 2012 and 2011, Penn West had no compound instruments outstanding.

s) Classification of debt or equity

Penn West classifies financial liabilities and equity instruments in accordance with the substance of the contractual arrangement and the definitions of a financial liability or an equity instrument.

Penn West's debt instruments currently have requirements to deliver cash at the end of the term and are classified as liabilities.

t) Enhanced oil recovery

The value of proprietary injectants is not recognized as revenue until reproduced and sold to third parties. The cost of injectants purchased from third parties for miscible flood projects is included in PP&E. Injectant costs are depleted over the period of expected future economic benefit on a unit-of-production basis. Costs associated with the production of proprietary injectants are expensed.

Future Accounting Pronouncements

In May 2011, the International Accounting Standards Board issued the following standards which are not yet effective:

IFRS 9 "Financial Instruments" outlines a new methodology for the recognition and measurement requirements for financial instruments. This new standard will eventually replace IAS 39 "Financial Instruments: Recognition and Measurement". The standard becomes effective for annual periods beginning on or after, January 1, 2015. This standard is still in development; therefore, Penn West cannot assess the impact of this standard at this time.

IFRS 10 "Consolidated Financial Statements" outlines a new methodology to determine whether to consolidate an investee. This new standard becomes effective for annual periods beginning on or after January 1, 2013. Penn West believes the adoption of this standard will have no material impact on its financial statements.

IFRS 11 "Joint Arrangements" outlines the accounting treatment for joint arrangements, notably joint operations which will follow the proportionate consolidation method and joint ventures which will follow the equity accounting method. This new standard becomes effective for annual periods beginning on or after January 1, 2013 and will apply to Penn West's interest in the Peace River Oil Partnership. Penn West currently believes that its interest in the Peace River Oil Partnership is appropriately classified as a joint operation; therefore, it will continue to proportionately consolidate its interest in the Partnership upon adoption of this standard.

IFRS 12 "Disclosure of Interests in Other Entities" outlines disclosure requirements for interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. These disclosure requirements are required for annual periods beginning on or after January 1, 2013. Penn West is currently assessing the impact of this standard.

IFRS 13 "Fair Value Measurement" defines fair value, provides guidance on measuring fair value and outlines disclosure requirements for fair value measurement. This standard applies when another IFRS standard requires fair value measurements or disclosures, with some exceptions including IFRS 2 "Share based payments" and IAS 17 "Leases". This new standard is applicable for annual periods beginning on or after January 1, 2013. Penn West is currently assessing the impact of this standard.

4. Working capital

	As at December 31	
	2012	2011
Components of accounts receivable		
Trade	**$138**	$ 130
Accruals	**226**	356
	$364	$ 486
Components of other assets		
Prepaid expenses	**$ 58**	$ 63
Other	**21**	41
	$ 79	$ 104
Components of accounts payable and accrued liabilities		
Accounts payable	**$225**	$ 296
Royalty payable	**72**	91
Capital accrual	**230**	399
Operating accrual	**172**	161
Share-based compensation liability	**24**	91
Other	**41**	70
	$764	$ 1,108

Accounts receivable

Penn West continuously monitors credit risk and maintains credit policies to ensure collection risk is limited. Receivables are primarily with customers in the oil and gas industry and are subject to normal industry credit risk. Receivables over 90 days are classified as past due and are assessed for collectability. If an amount is deemed to be uncollectible, it is expensed through income.

As at December 31, Penn West's credit assessments indicated that no items are currently considered to be uncollectible. As at December 31, the following accounts receivable amounts were outstanding.

	Current	30-90 days	90+ days	Total
2012	**$ 307**	**$ 21**	**$ 36**	**$364**
2011	$ 411	$ 68	$ 7	$486

5. Deferred funding assets

Deferred funding amounts relate to Penn West's share of capital and operating costs from Penn West's partner in the Peace River Oil Partnership and Penn West's share of capital expenditures from Penn West's partner in the Cordova Joint Venture. Amounts expected to be settled within the next 12 months are classified as current. In the second quarter of 2012, Penn West reclassified expected funding of capital and operating costs in 2012 of $236 million as a current asset at December 31, 2011.

	As at December 31	
	2012	**2011**
Peace River Oil Partnership	**$ 328**	$ 421
Cordova Joint Venture	**97**	175
Total	**$ 425**	$ 596
Current portion	**$ 187**	$ 236
Long-term portion	**238**	360
Total	**$ 425**	$ 596

6. Exploration and evaluation assets

	Year ended December 31	
	2012	2011
Balance, beginning of year	**$ 418**	$ 128
Capital expenditures	**110**	229
Joint venture, carried capital	**118**	92
Expense	**(17)**	(15)
Transfers to PP&E	**(16)**	(14)
Net dispositions	**(4)**	(2)
Balance, end of year	**$ 609**	$ 418

On December 31, 2012 and 2011 no impairment existed related to exploration and evaluation assets. An impairment test was completed on amounts reclassified into PP&E at which time the estimated fair value exceeded the carrying amount and no impairment was indicated.

7. Property, plant and equipment

Cost

	Oil and gas assets	Facilities	Turnarounds	Corporate assets	Total
Balance at January 1, 2011	$ 13,673	$4,769	$ 10	$ 102	$18,554
Capital expenditures	1,067	521	4	25	1,617
Joint venture, carried capital	15	—	—	—	15
Acquisitions	111	27	—	—	138
Dispositions	(337)	(38)	—	—	(375)
Transfers from E&E	11	3	—	—	14
Business combinations	286	—	—	—	286
Net decommissioning dispositions	(11)	(3)	—	—	(14)
Balance at December 31, 2011	**$ 14,815**	**$5,279**	**$ 14**	**$ 127**	**$20,235**
Capital expenditures	**951**	**675**	**—**	**16**	**1,642**
Joint venture, carried capital	**19**	**—**	**—**	**—**	**19**
Acquisitions	**42**	**10**	**—**	**—**	**52**
Dispositions	**(1,786)**	**(446)**	**—**	**—**	**(2,232)**
Transfers from E&E	**13**	**3**	**—**	**—**	**16**
Net decommissioning dispositions	**53**	**13**	**—**	**—**	**66**
Balance at December 31, 2012	**$ 14,107**	**$5,534**	**$ 14**	**$ 143**	**$19,798**

Accumulated depletion, depreciation and impairment

	Oil and gas assets	Facilities	Turnarounds	Corporate assets	Total
Balance at January 1, 2011	$ 5,469	$1,820	$ 9	$ 38	$7,336
Depletion and depreciation	969	190	1	8	1,168
Dispositions	(137)	(15)	—	—	(152)
Impairments	23	6	—	—	29
Impairment reversals	(31)	(8)	—	—	(39)
Balance at December 31, 2011	**$ 6,293**	**$1,993**	**$ 10**	**$ 46**	**$8,342**
Depletion and depreciation	**1,032**	**205**	**1**	**10**	**1,248**
Impairments	**277**	**—**	**—**	**—**	**277**
Dispositions	**(769)**	**(192)**	**—**	**—**	**(961)**
Balance at December 31, 2012	**$ 6,833**	**$2,006**	**$ 11**	**$ 56**	**$8,906**

Net book value

	As at December 31	
	2012	2011
Total	**$10,892**	$11,893

On December 31, 2012, Penn West recorded a $277 million impairment related to certain properties in northern British Columbia, primarily due to weak natural gas prices. The recoverable amount was based on the CGU's value-in-use. No impairment existed at December 31, 2011 relating to the capitalized costs of oil and natural gas properties.

In the first quarter of 2011, Penn West recorded an impairment reversal of $39 million due to stronger economic factors resulting in higher forecast cash flows from certain properties in central Alberta. This reversed a portion of an $80 million impairment recorded in the second quarter of 2010 in the same area. In the second quarter of 2011, Penn West recorded a $29 million impairment in the same area due to weaker commodity prices.

The impairment tests were completed using a pre-tax discount rate of 10 percent. Impairment reversals and losses have been included within depletion and depreciation.

The following table outlines benchmark prices at December 31, 2012 used in the impairment test:

	WTI ($US/ bbl)	AECO ($CAD/mcf)	Exchange rate ($US equals $1 CAD)
2013	$ 89.82	$ 3.35	1.00
2014	91.21	3.78	1.00
2015	91.64	4.09	1.00
2016	96.51	4.71	1.00
2017 – 2022	$ 100.43	$ 5.44	1.00
Thereafter (inflation percentage)	1.8%	1.8%	1.00

8. Goodwill

	Year ended December 31	
	2012	2011
Balance, beginning and end of year	**$ 2,020**	$ 2,020

A goodwill impairment test was completed at December 31, 2012 and 2011 at which time the recoverable amount exceeded the carrying value, thus no impairment was recorded. The recoverable amount was determined based on the fair value less costs to sell method. The key assumptions used in determining the recoverable amount include the future cash flows using reserve forecasts, the forecasted commodity prices (refer to Note 7 for assumptions at December 31, 2012), future development costs and the value of resources estimated by independent reserve engineers and other internal estimates.

9. Long-term debt

	As at December 31	
	2012	2011
Bankers' acceptances and prime rate loans	**$ 752**	$1,248
U.S. Senior unsecured notes – 2007 Notes		
5.68%, US$160 million, maturing May 31, 2015	**159**	163
5.80%, US$155 million, maturing May 31, 2017	**154**	158
5.90%, US$140 million, maturing May 31, 2019	**139**	142
6.05%, US$20 million, maturing May 31, 2022	**20**	20
Senior unsecured notes – 2008 Notes		
6.12%, US$153 million, maturing May 29, 2016	**152**	155
6.16%, CAD$30 million, maturing May 29, 2018	**30**	30
6.30%, US$278 million, maturing May 29, 2018	**276**	283
6.40%, US$49 million, maturing May 29, 2020	**49**	50
UK Senior unsecured notes – UK Notes		
6.95%, £57 million, maturing July 31, 2018 (1)	**91**	90
Senior unsecured notes – 2009 Notes		
8.29%, US$50 million, maturing May 5, 2014	**50**	51
8.89%, US$35 million, maturing May 5, 2016	**35**	36
9.32%, US$34 million, maturing May 5, 2019	**34**	35
8.89%, US$35 million, maturing May 5, 2019 (2)	**35**	36
9.15%, £20 million, maturing May 5, 2019 (3)	**32**	32
9.22%, €10 million, maturing May 5, 2019 (4)	**13**	13
7.58%, CAD$5 million, maturing May 5, 2014	**5**	5
Senior unsecured notes – 2010 Q1 Notes		
4.53%, US$28 million, maturing March 16, 2015	**27**	28
4.88%, CAD$50 million, maturing March 16, 2015	**50**	50
5.29%, US$65 million, maturing March 16, 2017	**65**	66
5.85%, US$112 million, maturing March 16, 2020	**112**	114
5.95%, US$25 million, maturing March 16, 2022	**25**	25
6.10%, US$20 million, maturing March 16, 2025	**20**	20
Senior unsecured notes – 2010 Q4 Notes		
4.44%, CAD$10 million, maturing December 2, 2015	**10**	10
4.17%, US$18 million, maturing December 2, 2017	**18**	18
5.38%, CAD$50 million, maturing December 2, 2020	**50**	50
4.88%, US$84 million, maturing December 2, 2020	**84**	86
4.98%, US$18 million, maturing December 2, 2022	**18**	18
5.23%, US$50 million, maturing December 2, 2025	**50**	51
Senior unsecured notes – 2011 Q4 Notes		
3.64%, US$25 million, maturing November 30, 2016	**25**	25
4.23%, US$12 million, maturing November 30, 2018	**12**	12
4.63%, CAD$30 million, maturing November 30, 2018	**30**	30
4.79%, US$68 million, maturing November 30, 2021	**68**	69
Total long-term debt	**$2,690**	$3,219

(1) These notes bear interest at 7.78 percent in Pounds Sterling, however, contracts were entered into which fixed the interest rate at 6.95 percent in Canadian dollars.
(2) This portion of the 2009 Notes has equal repayments, beginning in 2013, over the remaining seven years.
(3) These notes bear interest at 9.49 percent in Pounds Sterling, however, contracts were entered into which fixed the interest rate at 9.15 percent in Canadian dollars.
(4) These notes bear interest at 9.52 percent in Euros, however, contracts were entered into which fixed the interest rate at 9.22 percent in Canadian dollars.

Information on Penn West's senior unsecured notes was as follows:

	As at December 31	
	2012	2011
Weighted average remaining life (years)	**5.5**	6.5
Weighted average interest rate [(1)]	**6.1%**	6.1%

(1) Includes the effect of cross currency swaps.

The Company has a four-year, unsecured, revolving syndicated bank facility with an aggregate borrowing limit of $3.0 billion. The facility expires on June 30, 2016 and is extendible. The credit facility contains provisions for stamping fees on bankers' acceptances and LIBOR loans and standby fees on unutilized credit lines that vary depending on certain consolidated financial ratios. At December 31, 2012, the Company had approximately $2.2 billion of unused credit capacity available.

Drawings on the Company's credit facility are subject to fluctuations in short-term money market rates as they are generally held in short-term money market instruments. As at December 31, 2012, four percent (2011 – 19 percent) of Penn West's long-term debt instruments were exposed to changes in short-term interest rates.

Letters of credit totalling $5 million were outstanding on December 31, 2012 (2011 – $3 million) that reduce the amount otherwise available to be drawn on the syndicated facility.

Realized gains and losses on the interest rate swaps are recorded as financing costs. For 2012, an expense of $9 million (2011 – $12 million) was incurred to reflect that the floating interest rate was lower than the fixed interest rate transacted under our interest rate swaps.

The estimated fair values of the principal and interest obligations of the outstanding unsecured notes were as follows:

	As at December 31	
	2012	2011
2007 Notes	**$ 517**	$ 535
2008 Notes	**565**	584
UK Notes	**96**	89
2009 Notes	**235**	242
2010 Q1 Notes	**326**	334
2010 Q4 Notes	**237**	239
2011 Notes	**137**	139
Total	**$2,113**	$2,162

10. Decommissioning liability

The total decommissioning liability is based upon the present value of Penn West's net share of estimated future costs of obligations to abandon and reclaim all wells, facilities and pipelines. The estimates were made by management using external consultants assuming current costs, technology and enacted legislation.

The decommissioning liability was determined by applying an inflation factor of 2.0 percent (2011—2.0 percent) and the inflated amount was discounted using a credit-adjusted rate of 7.0 percent (2011—7.0 percent) over the expected useful life of the underlying assets, currently extending over 50 years into the future with a weighted average life of 32 years.

Changes to the decommissioning liability were as follows:

	Year ended December 31	
	2012	2011
Balance, beginning of year	**$ 607**	$ 648
Net liabilities incurred (disposed) (1)	**(166)**	(19)
Increase in liability due to changes in estimates	**232**	12
Liabilities settled	**(92)**	(81)
Liabilities acquired	**—**	2
Accretion charges	**54**	45
Balance, end of year	**$ 635**	$ 607

(1) Includes additions from drilling activity, facility capital spending and disposals from net property dispositions.

11. Risk management

Financial instruments included in the balance sheets consist of accounts receivable, fair values of derivative financial instruments, accounts payable and accrued liabilities, dividends payable and long-term debt. Except for the senior, unsecured notes described in Note 9, the fair values of these financial instruments approximate their carrying amounts due to the short-term maturity of the instruments, the mark to market values recorded for the financial instruments and the market rate of interest applicable to the bank facility.

The fair values of all outstanding financial, commodity, power, interest rate and foreign exchange contracts are reflected on the balance sheet with the changes during the period recorded in income as unrealized gains or losses.

As at December 31, 2012 and 2011, the only asset or liability measured at fair value on a recurring basis was the risk management asset and liability, which was valued based on “Level 2 inputs” being quoted prices in markets that are not active or based on prices that are observable for the asset or liability.

A comparison of the carrying value to the fair value of the financial instruments included in the balance sheet was as follows:

		Carrying value		Fair value	
	Classification	**2012**	2011	**2012**	2011
Accounts receivable	Loans and receivables	**$ 364**	$ 486	**$ 364**	$ 486
Derivative financial assets	FV through profit/loss	**102**	67	**102**	67
Derivative financial liabilities	FV through profit/loss	**44**	160	**44**	160
Accounts payable and accrued liabilities	Financial liabilities	**764**	1,108	**764**	1,108
Dividends payable	Financial liabilities	**129**	127	**129**	127
Bankers’ acceptances and prime rate loans	Financial liabilities	**752**	1,248	**752**	1,248
Senior notes (1)	Financial liabilities	**$1,938**	$1,971	**$2,113**	$2,162

(1) Calculated as the present value of the interest and principal payments at December 31.

The following table reconciles the changes in the fair value of financial instruments outstanding:

Risk management asset (liability)	Year ended December 31 2012	2011
Balance, beginning of year	**$ (93)**	$ (126)
Unrealized gain (loss) on financial instruments:		
Commodity collars and swaps	**156**	8
Electricity swaps	**(28)**	35
Interest rate swaps	**12**	(8)
Foreign exchange forwards	**1**	(4)
Cross currency swaps	**10**	2
Total fair value, end of year	**$ 58**	$ (93)
Total fair value consists of the following:		
Fair value, end of year – current asset portion	**$ 76**	$ 39
Fair value, end of year – current liability portion	**(9)**	(114)
Fair value, end of year – non-current asset portion	**26**	28
Fair value, end of year – non-current liability portion	**(35)**	(46)
Total fair value, end of year	**$ 58**	$ (93)

Based on December 31, 2012 pricing, a $1.00 change in the price per barrel of liquids would change pre-tax unrealized risk management by $13 million and a $0.10 change in the price per mcf of natural gas would change pre-tax unrealized risk management by $6 million.

Penn West had the following financial instruments outstanding as at December 31, 2012. Fair values are determined using external counterparty information, which is compared to observable market data. Penn West limits its credit risk by executing counterparty risk procedures which include transacting only with institutions within our credit facility or with high credit ratings and by obtaining financial security in certain circumstances.

	Notional volume	Remaining term	Pricing	Fair value (millions)
Crude oil				
WTI Collars	55,000 bbls/d	Jan/13—Dec/13	US$91.55 to $104.42/bbl	$ 66
Natural gas				
AECO Forwards	125,000 mcf/d	Jan/13—Dec/13	$3.34/mcf	9
AECO Forwards	25,000 mcf/d	Jan/14—Dec/14	$3.85/mcf	2
AECO Collars	25,000 mcf/d	Jan/14—Dec/14	$3.25 to $4.35/mcf	—
Electricity swaps				
Alberta Power Pool	30 MW	Jan/13—Dec/13	$54.60/MWh	1
Alberta Power Pool	20 MW	Jan/13—Dec/13	$56.10/MWh	1
Alberta Power Pool	70 MW	Jan/14—Dec/14	$58.50/MWh	(5)
Alberta Power Pool	10 MW	Jan/14—Dec/15	$58.50/MWh	(1)
Alberta Power Pool	45 MW	Jan/15—Dec/15	$58.28/MWh	(4)
Alberta Power Pool	25 MW	Jan/16—Dec/16	$49.90/MWh	—
Interest rate swaps	$650	Jan/13—Jan/14	2.65%	(10)
Foreign exchange forwards on senior notes				
3 to 15-year initial term	US$641	2014—2022	1.000 CAD/USD	23
Cross currency swaps				
10-year initial term	£57	2018	2.0075 CAD/GBP, 6.95%	(19)
10-year initial term	£20	2019	1.8051 CAD/GBP, 9.15%	(3)
10-year initial term	€10	2019	1.5870 CAD/EUR, 9.22%	(2)
Total				$ 58

A realized gain of $7 million (2011—$11 million) on electricity contracts has been included in operating costs for 2012.

Subsequent to December 31, 2012, Penn West entered into foreign exchange forward contracts on revenue from March 2013 to December 2013 on $153 million per month at an average foreign exchange rate of 1.022 CAD/USD. It also entered into additional natural gas collars on 25,000 mcf per day in 2014 between $3.57 per mcf and $4.00 per mcf.

Additionally, Penn West has subsequently entered into oil differential contracts from March to June 2013 on 4,000 barrels per day. These contracts fix the price of MSW (mixed sweet crudes at Edmonton) at a discount of USD $8.00 per barrel to WTI.

Market Risks

Penn West is exposed to normal market risks inherent in the oil and natural gas business, including, but not limited to, commodity price risk, foreign currency rate risk, credit risk, interest rate risk and liquidity risk. The Company seeks to mitigate these risks through various business processes and management controls and from time to time by using financial instruments.

Commodity Price Risk

Commodity price fluctuations are among the Company's most significant exposures. Crude oil prices are influenced by worldwide factors such as OPEC actions, world supply and demand fundamentals and geopolitical events. Natural gas prices are influenced by the price of alternative fuel sources such as oil or coal and by North American natural gas supply and demand fundamentals including the levels of industrial activity, weather, storage levels and liquefied natural gas activity. In accordance with policies approved by Penn West's Board of Directors, the Company may, from time to time, manage these risks through the use of swaps, collars or other financial instruments up to a maximum of 50 percent of forecast sales volumes, net of royalties, for the balance of any current year plus one additional year forward and up to a maximum of 25 percent, net of royalties, for one additional year thereafter. Risk management limits included in Penn West's policies may be exceeded with specific approval from the Board of Directors.

Foreign Currency Rate Risk

Prices received for crude oil are referenced to US dollars, thus Penn West's realized oil prices are impacted by Canadian dollar to US dollar exchange rates. A portion of the Company's debt capital is denominated in US dollars, thus the principal and interest payments in Canadian dollars are also impacted by exchange rates. When considered appropriate, the Company may use financial instruments to fix or collar future exchange rates to fix the Canadian dollar equivalent of crude oil revenues or to fix US denominated long-term debt principal repayments. At December 31, 2012, the following foreign currency forward contracts were outstanding:

Nominal Amount	Settlement date	Exchange rate
Buy US$20	2014	0.99885 CAD/USD
Buy US$76	2015	1.00705 CAD/USD
Buy US$74	2016	0.99838 CAD/USD
Buy US$104	2017	0.99895 CAD/USD
Buy US$113	2018	0.99885 CAD/USD
Buy US$100	2019	0.99386 CAD/USD
Buy US$134	2020	0.99885 CAD/USD
Buy US$20	2022	0.98740 CAD/USD

At December 31, 2012, Penn West had US dollar denominated debt with a face value of US$1.0 billion (2011—US$1.0 billion) on which the repayment of the principal amount in Canadian dollars was not fixed.

Credit Risk

Credit risk is the risk of loss if purchasers or counterparties do not fulfill their contractual obligations. The Company's accounts receivable are principally with customers in the oil and natural gas industry and are generally subject to normal industry credit risk, which includes the ability to recover unpaid receivables by retaining the partner's share of production when Penn West is the operator. For oil and natural gas sales and financial derivatives, a counterparty risk procedure is followed whereby each counterparty is reviewed on a regular basis for the purpose of assigning a credit limit and may be requested to provide security if determined to be prudent. For financial derivatives, the Company normally transacts with counterparties who are members of the banking syndicate or other counterparties that have investment grade bond ratings. Credit events related to all counterparties are monitored and credit exposures are reassessed on a regular basis. As necessary, provisions for potential credit related losses are recognized.

As at December 31, 2012, the maximum exposure to credit risk was $364 million (2011—$486 million) being the carrying value of the accounts receivable.

Interest Rate Risk

A portion of the Company's debt capital is held in floating-rate bank facilities which results in exposure to fluctuations in short-term interest rates which remain at lower levels than longer-term rates. From time to time, Penn West may increase the certainty of its future interest rates by entering fixed interest rate debt instruments or by using financial instruments to swap floating interest rates for fixed rates or to collar interest rates. As at December 31, 2012, four percent of the Company's long-term debt instruments were exposed to changes in short-term interest rates (2011 – 19 percent).

As at December 31, 2012, a total of $1.9 billion (2011 – $2.0 billion) of fixed interest rate debt instruments was outstanding with an average remaining term of 5.5 years (2011 – 6.5 years) and an average interest rate of 5.8 percent (2011 – 5.9 percent), including the effects of interest rate swaps.

Liquidity Risk

Liquidity risk is the risk that the Company will be unable to meet its financial liabilities as they come due. Management utilizes short and long-term financial and capital forecasting programs to ensure credit facilities are sufficient relative to forecast debt levels, dividend and capital program levels are appropriate, and that financial covenants will be met. Management also regularly reviews capital markets to identify opportunities to optimize the debt capital structure on a cost effective basis. In the short term, liquidity is managed through daily cash management activities, short-term financing strategies and the use of collars and other financial instruments to increase the predictability of cash flow from operating activities.

The following table outlines estimated future obligations for non-derivative financial liabilities as at December 31, 2012:

	2013	2014	2015	2016	2017	Thereafter
Bank debt	**$—**	$—	$—	$752	$—	$ —
Senior unsecured notes	**5**	60	251	216	242	1,164
Accounts payable and accrued liabilities	**740**	—	—	—	—	—
Dividends payable	**129**	—	—	—	—	—
Share-based compensation accrual	**24**	5	—	—	—	—
Total	**$898**	$ 65	$251	$968	$242	$ 1,164

12. Income taxes

The provision for income taxes is as follows:

Deferred tax expense (recovery)	Year ended December 31 2012	2011
Changes in temporary differences	**$ 63**	$ 89
Changes in tax rates and laws	**—**	(316)
Deferred tax expense (recovery)	**$ 63**	$ (227)

On January 1, 2011, Penn West recorded a $304 million recovery related to a change in tax rates on conversion from an income trust to a corporation. On the conversion to a corporation, deferred income tax assets and liabilities were re-measured at the applicable corporate income tax rate of approximately 26 percent. Under the trust structure, Penn West was required to provide for deferred tax on timing differences at the trust level at rates of approximately 39 percent, representing the rate applicable to undistributed earnings of the trust. At that time, Penn West also recorded a net tax recovery of $45 million related to changes to Penn West's equity-based compensation plans.

The provision for income taxes reflects an effective tax rate that differs from the combined federal and provincial statutory tax rate as follows:

	Year ended December 31 2012	2011
Income before taxes	**$ 237**	$ 411
Combined statutory tax rate	**25.4%**	26.9%
Computed income tax expense	**$ 60**	$ 111
Increase (decrease) resulting from:		
Effective rate change from SIFT temporary differences	**—**	(304)
Share-based compensation	**7**	(20)
Unrealized foreign exchange	**(5)**	5
Adjustment for previously enacted tax rates	**—**	(5)
Other	**1**	(14)
Deferred tax expense (recovery)	**$ 63**	$ (227)

The tax rate declined from the prior year as a result of previously enacted reductions in federal corporate income tax rates.

Penn West has income tax filings that are subject to audit by taxation authorities which may impact its deferred tax liability. Penn West does not anticipate adjustments arising from these audits and believes it has adequately provided for income taxes based on available information.

The net deferred income tax liability is comprised of the following:

	Balance January 1, 2011	Provision (Recovery) in Income	Provision in Business Combinations	Balance December 31, 2011
Deferred tax liabilities (assets)				
PP&E	$ 2,279	$ (84)	$ 61	$ 2,256
Risk management	(32)	6	—	(26)
Decommissioning liability	(165)	—	1	(164)
Stock-based compensation	—	(26)	—	(26)
Non-capital losses	(630)	(123)	—	(753)
Net deferred tax liability	$ 1,452	$ (227)	$ 62	$ 1,287

	Balance January 1, 2012	Provision (Recovery) in Income	Provision in Business Combinations	**Balance December 31, 2012**
Deferred tax liabilities (assets)				
PP&E	$ 2,256	$ (266)	$ —	**$ 1,990**
Risk management	(26)	52	—	**26**
Decommissioning liability	(164)	3	—	**(161)**
Stock-based compensation	(26)	19	—	**(7)**
Non-capital losses	(753)	255	—	**(498)**
Net deferred tax liability	$ 1,287	$ 63	$ —	**$ 1,350**

13. Shareholders' equity

a) Authorized

i) An unlimited number of Common Shares.

ii) 90,000,000 Preferred Shares issuable in one or more series.

Penn West has a Dividend Reinvestment and Optional Share Purchase Plan (the "DRIP") that provides eligible shareholders the opportunity to reinvest quarterly cash dividends into additional common shares at a potential discount. Common shares are issued from Treasury at 95 percent of the 10-day volume-weighted average market price when available. When common shares are not available from Treasury they are acquired in the open market at prevailing market prices.

Eligible shareholders who participate in the DRIP may also purchase additional common shares, subject to a quarterly maximum of $15,000 and a minimum of $500. Optional cash purchase common shares are acquired in the open market at prevailing market prices or issued from Treasury, without a discount at the 10-day volume-weighted average market price.

If issued, Preferred shares of each series would rank on parity with the Preferred shares of other series with respect to accumulated dividends and return on capital. Preferred shares would have priority over the Common shares with respect to the payment of dividends or the distribution of assets.

b) Issued

Shareholders' capital/ Unitholders' capital	Common Shares/Trust Units	Amount
Balance, January 1, 2011	459,682,249	$ 9,170
Cancellation of trust units on January 1, 2011	(459,682,249)	(9,170)
Issuance of shares on January 1, 2011	459,682,249	9,170
Elimination of deficit	—	(610)
Issued on exercise of equity compensation plans (1)	6,955,666	188
Issued to dividend reinvestment plan	4,734,815	92
Balance, January 1, 2012	471,372,730	$ 8,840
Issued on exercise of equity compensation plans (1)	**229,633**	**28**
Issued to dividend reinvestment plan	**7,779,185**	**117**
Cancellations (2)	**(122,878)**	**—**
Balance, December 31, 2012	**479,258,670**	**$ 8,985**

(1) Upon exercise of options, the net benefit is recorded as a reduction of other reserves and an increase to shareholders' capital. Included are 15,364 shares issued from Treasury (2011—88,629) due to individuals settling restricted rights in exchange for common shares.
(2) Represents shares cancelled pursuant to Sunset clauses contained in prior corporate acquisitions.

Upon commencement of operations as a corporation, pursuant to the Plan of Arrangement and a resolution of the Board of Directors, Penn West's recorded deficit of $610 million as at December 31, 2010 was eliminated against share capital on January 1, 2011.

	Year ended December 31	
Other Reserves	2012	2011
Balance, beginning of year	**$ 95**	$ —
Set-up of Option Plan and CSRIP	**—**	81
Share-based compensation expense	**27**	41
Net benefit on options exercised (1)	**(25)**	(27)
Balance, end of year	**$ 97**	$ 95

(1) Upon exercise of options, the net benefit is recorded as a reduction of other reserves and an increase to shareholders' capital.

Preferred Shares

No Preferred Shares were issued or outstanding.

14. Share-based compensation

Stock Option Plan (the "Option Plan")

Penn West has an Option Plan that allows Penn West to issue options to acquire common shares to officers, employees and other service providers. The plan was effective on January 1, 2011, the date of conversion to a corporation. Prior to 2011, employees held trust unit rights under the Trust Unit Rights Incentive Plan ("TURIP").

To date, no options have been granted to other service providers. The number of options reserved for issuance under the Option Plan plus the number of common share rights reserved for issuance under the CSRIP shall not exceed nine percent of the aggregate number of issued and outstanding common shares of Penn West. The grant price of options is equal to the volume-weighted average trading price of the common shares on the TSX for a five-trading-day period immediately preceding the date of grant. Options granted to date vest over a four-year period and expire five years after the date of grant.

Options	Year ended December 31 2012 Number of Options	2012 Weighted Average Exercise Price	2011 Number of Options	2011 Weighted Average Exercise Price
Outstanding, beginning of year	**7,919,600**	**$ 25.73**	—	$ —
Granted	**9,202,900**	**19.88**	8,531,536	25.84
Exercised	**—**	**—**	—	—
Forfeited	**(1,385,100)**	**23.05**	(611,936)	27.34
Outstanding, end of year	**15,737,400**	**$ 22.54**	7,919,600	$ 25.73
Exercisable, end of year	**2,566,282**	**$ 25.05**	—	$ —

Range of Grant Prices	Options Outstanding Number Outstanding	Weighted Average Exercise Price	Weighted Remaining Contractual Life (years)	Options Exercisable Number Exercisable	Weighted Average Exercise Price
$9.00—$13.99	533,100	$ 11.83	5.0	—	$ —
$14.00—$18.99	1,652,700	15.58	4.4	165,125	16.23
$19.00—$23.99	7,679,810	21.05	4.2	652,029	20.84
$24.00—$28.99	5,871,790	27.43	3.3	1,749,128	27.44
	15,737,400	$ 22.54	3.9	2,566,282	$ 25.05

Common Share Rights Incentive Plan ("CSRIP")

Restricted Options and Restricted Rights

Prior to 2011, holders held trust unit rights under the TURIP. On the effective date of conversion to a corporation, pursuant to the Plan of Arrangement, holders of trust unit rights could elect to exchange one outstanding "in-the-money" trust unit right for one Restricted Option and one Restricted Right. The Restricted Option and the Restricted Right must be exercised simultaneously with the Restricted Option settled in equity while the Restricted Right can be settled in common shares or cash. Restricted Options and Restricted Rights vest between a three and five-year period and expire four to six years after the date of the grant. Subsequent to January 1, 2011 only stock options will be granted under the Option Plan.

Restricted Options	Year ended December 31 2012 Number of Restricted Options	2012 Weighted Average Exercise Price	2011 Number of Restricted Options	2011 Weighted Average Exercise Price
Outstanding, beginning of year	**17,110,193**	**$ 23.84**	—	$ —
Exchange of TURIP	**—**	**—**	27,586,712	23.84
Exercised [1]	**—**	**—**	(6,188,414)	23.84
Forfeited	**(6,574,832)**	**23.84**	(4,288,105)	23.84
Outstanding, end of year	**10,535,361**	**$ 23.84**	17,110,193	$ 23.84
Exercisable, end of year	**8,782,046**	**$ 23.84**	10,171,239	$ 23.84

(1) No restricted options were exercised in 2012; the weighted average share price on restricted options exercised in 2011 was $26.20 per share.

Restricted Rights	Year ended December 31 2012 Number of Restricted Rights	2012 Weighted Average Exercise Price	2011 Number of Restricted Rights	2011 Weighted Average Exercise Price
Outstanding, beginning of year	**17,110,193**	**$ 15.15**	—	$ —
Exchange of TURIP	**—**	**—**	27,586,712	16.11
Exercised [1]	**(4,891,135)**	**14.44**	(9,061,792)	15.13
Forfeited	**(1,683,697)**	**$ 17.68**	(1,414,727)	16.45
Outstanding, end of year	**10,535,361**	**$ 13.32**	17,110,193	$ 15.15
Exercisable, end of year	**8,782,046**	**$ 12.41**	10,171,239	$ 15.10

(1) The weighted average share price of restricted rights exercised in 2012 was $19.84 per share (2011—$22.38 per share).
(2) Weighted average exercise price includes reductions of the exercise price for dividends paid.

The fair value of the Restricted Rights is classified as a liability due to the cash settlement feature. At December 31, 2012, $15 million was classified as a current liability (2011 – $84 million) included in accounts payable and accrued liabilities.

Range of Adjusted Grant Prices	Restricted Rights Outstanding Number Outstanding	Weighted Average Exercise Price [1]	Weighted Remaining Contractual Life (years) [2]	Restricted Rights Exercisable Number Exercisable	Weighted Average Exercise Price [1]
$9.00—$14.99	4,400,605	$ 7.44	0.5	4,400,605	$ 7.44
$15.00—$20.99	3,815,662	16.66	1.3	2,691,337	16.38
$21.00—$26.99	2,219,344	18.86	1.4	1,590,354	18.85
$27.00—$38.99	99,750	21.77	0.3	99,750	21.77
	10,535,361	$ 13.32	1.0	8,782,046	$ 12.41

(1) Weighted average exercise price includes reductions of the exercise price for dividends/ distributions paid.
(2) Rights granted under the plan prior to November 13, 2006 expire after 6 years, rights granted after this date expired after 4 years.

Share Rights

On the date of the conversion to a corporation, trust unit right holders who did not elect to exchange their trust unit rights for a Restricted Option and Restricted Right, as described above, or who held “out-of-the-money” trust unit rights were issued Share Rights under the CSRIP in exchange for their trust unit rights. Share Rights were issued with the same or similar features to trust unit rights including vesting terms, grant prices and the reduction of the exercise price for dividends paid in certain circumstances. Share Rights vest between a three and five-year period and expire four to six years after the date of the grant. No new Share Rights will be granted after January 1, 2011.

	Year ended December 31			
	2012		2011	
Share Rights	**Number of Share Rights**	**Weighted Average Exercise Price**	Number of Share Rights	Weighted Average Exercise Price
Outstanding, beginning of year	**2,549,112**	**$ 23.13**	—	$ —
Exchange of TURIP	**—**	**—**	3,778,766	22.46
Exercised (1)	**(214,269)**	**$ 13.29**	(678,623)	15.15
Forfeited	**(2,043,205)**	**$ 24.40**	(551,031)	22.21
Outstanding, end of year (2)	**291,638**	**$ 11.99**	2,549,112	$ 23.13
Exercisable, end of year	**253,665**	**$ 11.21**	2,325,725	$ 24.14

(1) The weighted average share price on share rights exercised in 2012 was $19.54 per share (2011—$24.82 per share).
(2) Weighted average exercise price includes reductions of the exercise price for dividends/ distributions paid.

	CSRIP Outstanding			CSRIP Exercisable	
Range of Grant Prices	Number Outstanding	Weighted Average Exercise Price (1)	Weighted Remaining Contractual Life (years) (2)	Number Exercisable	Weighted Average Exercise Price (1)
$9.00—$15.99	147,362	$ 7.26	0.5	147,362	$ 7.26
$16.00—$22.99	128,276	16.21	1.3	90,303	15.78
$23.00—$36.99	16,000	21.77	0.3	16,000	21.77
	291,638	$ 11.99	0.8	253,665	$ 11.21

(1) Weighted average exercise price includes reductions of the exercise price for dividends/ distributions paid.
(2) Rights granted under the plan prior to November 13, 2006 expire after 6 years, rights granted after this date expire after 4 years.

TURIP

Prior to conversion to a corporation on January 1, 2011, Penn West had a trust unit rights incentive plan that allowed Penn West to issue trust unit rights to directors, officers, employees and other service providers. Upon conversion, all trust unit rights were exchanged for either a Restricted Option with a Restricted Right or a Share Right.

TURIP	Year ended December 31 2012 Number of Unit Rights	2012 Weighted Average Exercise Price	2011 Number of Unit Rights	2011 Weighted Average Exercise Price
Outstanding, beginning of year	—	$ —	31,365,478	$ 16.88
Exchange for Restricted Options/ Rights	—	—	(27,586,712)	16.11
Exchange for Share Rights	—	—	(3,778,766)	22.46
Outstanding, end of year [1]	—	$ —	—	$ —
Exercisable, end of year	—	$ —	—	$ —

(1) Weighted average price included reductions of the exercise price for distributions paid.

Long-term retention and incentive plan ("LTRIP")

Under the LTRIP, Penn West employees receive cash consideration based on Penn West's share price. Eligible employees receive a grant of a specific number of LTRIP awards (each of which notionally represents a common share) that vest equally over a three-year period with the cash value paid to the employee on each vesting date. The cash consideration paid will vary depending upon the performance of the Penn West share price on the TSX. If the service requirements are met, the cash consideration paid is based on the number of LTRIP awards vested and the five-day weighted average trading price of the common shares prior to the vesting date plus dividends declared by Penn West and having a record date during the period preceding the vesting date.

LTRIP awards (number of shares equivalent)	Year ended December 31 2012	2011
Outstanding, beginning of year	**1,411,676**	700,669
Granted	**1,345,829**	1,076,556
Vested and paid	**(516,763)**	(224,050)
Forfeited	**(289,087)**	(141,499)
Outstanding, end of year	**1,951,655**	1,411,676

At December 31, 2012, LTRIP obligations of $9 million were classified as a current liability (2011—$9 million) included in accounts payable and accrued liabilities and $5 million were classified as a non-current liability (2011—$7 million) included in other non-current liabilities.

Share-based compensation

Share-based compensation is based on the fair value of the options at the time of grant under the Option Plan and the CSRIP, amortized over the remaining vesting period on a graded vesting schedule. Share-based compensation under the Restricted Rights and LTRIP is based on the fair value of the awards outstanding at the reporting date and is amortized based on a graded vesting schedule. Share-based compensation consisted of the following:

	Year ended December 31	
	2012	2011
Options	**$ 21**	$ 18
Restricted Options	**6**	22
Restricted Rights	**(45)**	(29)
Share Rights	**—**	1
LTRIP	**8**	14
Expiry of TURIP on January 1, 2011	**—**	(196)
Share Rights at January 1, 2011	**—**	16
Restricted Options on January 1, 2011	**—**	65
Restricted Rights liability on January 1, 2011	**—**	173
Share-based compensation	**$ (10)**	$ 84

The share price used in the fair value calculation of the LTRIP obligation and Restricted Rights obligation at December 31, 2012 was $10.80 (2011—$20.19).

On January 1, 2011, the TURIP liability was removed and a liability was recorded to reflect the Restricted Rights and the fair value of the Restricted Options and the Shares Rights were recorded in other reserves.

A Black-Scholes option-pricing model was used to determine the fair value of options granted under the Option Plan with the following fair value per option and weighted average assumptions:

	Year ended December 31	
	2012	2011
Average fair value of options granted (per share)	**$ 2.37**	$ 6.26
Expected life of restricted options (years)	**4.0**	4.0
Expected volatility (average)	**32.9%**	29.9%
Risk-free rate of return (average)	**1.3%**	1.9%
Dividend yield	**7.8%**	5.3%

Employee retirement savings plan

Penn West has an employee retirement savings plan (the “savings plan”) for the benefit of all employees. Under the savings plan, employees may elect to contribute up to 10 percent of their salary and Penn West matches these contributions at a rate of $1.50 for each $1.00 of employee contribution. Both the employee’s and Penn West’s contributions are used to acquire Penn West common shares or are placed in low-risk investments. Shares are purchased in the open market at prevailing market prices.

Deferred Share Unit plan (“DSU”)

The DSU plan became effective January 1, 2011, allowing Penn West to grant DSUs in lieu of cash compensation to non-executive directors providing a right to receive, upon retirement, a cash payment based on the volume-weighted-average trading price of the common shares on the TSX for the five trading days immediately prior to the day of payment. Management directors are not eligible to participate in the DSU Plan. At December 31, 2012, 37,416 DSUs were outstanding (2011—14,390).

Performance Share Unit plan ("PSU")

The PSU plan became effective February 13, 2013, allowing Penn West to grant PSUs to employees of Penn West. Upon meeting the vesting conditions, the employee will receive a cash payment based on performance thresholds determined by the Board of Directors. Members of the Board of Directors are ineligible for the PSU Plan.

15. Dividends

Dividends are paid quarterly at the discretion of the Board of Directors and are deducted from retained earnings.

In 2012, Penn West paid dividends of $512 million or $1.08 per share (2011—$420 million or $0.90 per share).

On January 15, 2013, Penn West paid its fourth quarter dividend of $0.27 per share totalling $129 million. On February 13, 2013, Penn West declared its first quarter 2013 dividend of $0.27 per share to be paid on April 15, 2013 to shareholders of record at the close of business on March 28, 2013.

16. Per share amounts

The number of incremental shares included in diluted earnings per share is computed using the average volume-weighted market price of shares for the period. In addition, contracts that could be settled in cash or shares are assumed to be settled in shares if share settlement is more dilutive.

	Year ended December 31	
(millions)	**2012**	2011
Diluted net income	**$ 174**	$ 638

The weighted average number of shares used to calculate per share amounts is as follows:

	Year ended December 31	
	2012	2011
Basic	**475,603,963**	467,186,047
Dilutive Impact	**204,019**	260,241
Diluted	**475,807,982**	467,446,288

For 2012, 25.3 million shares (2011 – 26.2 million) that would be issued under the Option Plan and CSRIP were excluded in calculating the weighted average number of diluted shares outstanding as they were considered anti-dilutive.

17. Changes in non-cash working capital (increase) decrease

	Year ended December 31	
	2012	2011
Accounts receivable	**$ 122**	$ (95)
Other current assets	**17**	(17)
Deferred funding obligation	**34**	(25)
Accounts payable and accrued liabilities	**(304)**	201
	$ (131)	$ 64
Operating activities	**$ 37**	$ (49)
Investing activities	**(168)**	113
	$ (131)	$ 64
Interest paid	**$ 204**	$ 189
Income taxes recovered	**$ —**	$ —

18. Business combinations

Spartan Exploration Ltd. (“Spartan”) Acquisition

On June 1, 2011, Penn West closed the acquisition of Spartan, a publicly traded oil and gas exploration company. The total cost was $166 million with $286 million recorded to property, plant and equipment. Penn West accounted for the Spartan acquisition as a business combination. The consolidated financial statements of Penn West include the results of operations of Spartan from the closing date of June 1, 2011.

19. Capital management

Penn West manages its capital to provide a flexible structure to support capital programs, dividend policies, production maintenance and other operational strategies. Maintaining a strong financial position enables the capture of business opportunities and supports Penn West’s business strategy of providing shareholder return through a combination of growth and yield.

Shareholders’ equity and long-term debt are defined as capital by Penn West. Shareholders’ equity includes shareholders’ capital, other reserves and retained earnings (deficit). Long-term debt includes bank loans and senior unsecured notes.

Management continuously reviews Penn West’s capital structure to ensure the objectives and strategies of Penn West are being met. The capital structure is reviewed based on a number of key factors including, but not limited to, current market conditions, trailing and forecast debt to capitalization ratios and debt to EBITDA and other economic risk factors. Currently dividends are paid quarterly at the discretion of Penn West’s Board of Directors.

The Company is subject to certain quarterly financial covenants under its unsecured, syndicated credit facility and the senior unsecured notes. These financial covenants are typical for senior unsecured lending arrangements and include senior debt and total debt to EBITDA and senior debt and total debt to capitalization as defined in Penn West’s lending agreements. As at December 31, 2012, the Company was in compliance with all of its financial covenants.

(millions, except ratio amounts)	Year ended December 31 2012	2011
Components of capital		
Shareholders' equity	**$ 8,874**	$ 9,067
Long-term debt	**$ 2,690**	$ 3,219
Ratios		
Senior debt to EBITDA (1)	**2.1**	1.9
Total debt to EBITDA (2)	**2.1**	1.9
Senior debt to capitalization (3)	**23%**	26%
Total debt to capitalization (4)	**23%**	26%
Priority debt to consolidated tangible assets (5)	**—**	—
EBITDA (6)	**$ 1,291**	$ 1,736
Credit facility debt and senior notes	**$ 2,690**	$ 3,219
Letters of credit	**5**	3
Senior debt and total debt	**2,695**	3,222
Total shareholders' equity	**8,874**	9,067
Total capitalization	**$11,569**	$12,289

(1) Less than 3:1 and not to exceed 3.5:1 in the event of a material acquisition.
(2) Less than 4:1.
(3) Not to exceed 50 percent except in the event of a material acquisition when the ratio is not to exceed 55 percent.
(4) Not to exceed 55 percent except in the event of a material acquisition when the ratio is not to exceed 60 percent.
(5) Priority debt not to exceed 15% of consolidated tangible assets.
(6) EBITDA is calculated in accordance with Penn West's lending agreements wherein unrealized risk management and impairment provisions are excluded.

20. Commitments and contingencies

Penn West is committed to certain payments over the next five calendar years as follows:

(millions)	2013	2014	2015	2016	2017	Thereafter
Long-term debt	**$ 5**	$ 60	$251	$968	$242	$ 1,164
Transportation	**24**	17	10	4	1	—
Transportation ($US)	**4**	37	37	33	33	198
Power infrastructure	**29**	14	14	14	14	12
Drilling rigs	**23**	21	17	11	6	—
Purchase obligations (1)	**6**	5	5	1	1	1
Interest obligations	**146**	142	132	105	77	136
Office lease (2)	**62**	56	55	54	52	384
Decommissioning liability (3)	**$100**	$ 95	$ 91	$ 87	$ 82	$ 180

(1) These amounts represent estimated commitments of $13 million for CO2 purchases and $6 million for processing fees related to our interests in the Weyburn Unit.
(2) The future office lease commitments above will be reduced by sublease recoveries totalling $335 million. For 2012, lease cost, net of recoveries totalled $28 million.
(3) These amounts represent the inflated, discounted future reclamation and abandonment costs that are expected to be incurred over the life of the properties.

Penn West's syndicated credit facility is due for renewal on June 30, 2016. If Penn West is not successful in renewing or replacing the facility, it could enter other facilities including term bank loans. In addition, Penn West has an aggregate of $1.9 billion in senior notes maturing between 2014 and 2025. Penn West continuously monitors its credit metrics and maintains positive working relationships with its lenders, investors and agents.

Penn West's other commitments relate to the following:

- Transportation commitments relate to costs for future pipeline access.
- Power infrastructure commitments pertain to electricity contracts.
- Drilling rigs are contracts held with service companies to ensure Penn West has access to specific drilling rigs at the required times.
- Purchase obligations relate to Penn West's commitments for CO2 purchases and processing fees related to Penn West's interests in the Weyburn CO2 miscible flood property in S.E. Saskatchewan.
- Interest obligations are the estimated future interest payments related to Penn West's debt instruments.
- Office leases pertain to total leased office space. A portion of this office space has been sub-leased to other parties to minimize Penn West's net exposure under the leases.

Penn West is involved in various litigation and claims in the normal course of business and records provisions for claims as required.

21. Related-party transactions

Operating entities

The consolidated financial statements include the results of Penn West Petroleum Ltd. and its wholly-owned subsidiaries, notably the Penn West Petroleum Partnership. Transactions and balances between Penn West Petroleum Ltd. and all of its subsidiaries are eliminated upon consolidation.

Compensation of key management personnel

Key management personnel include the President and Chief Executive Officer, Executive Vice Presidents, Senior Vice-Presidents and the Board of Directors. The Human Resources & Compensation Committee makes recommendations to the Board of Directors who approves the appropriate remuneration levels for management based on performance and current market trends. Compensation levels of the Board of Directors are recommended by the Corporate Governance committee of the Board. The remuneration of the directors and key management personnel of Penn West during the year is below.

	Year-ended December 31	
	2012	2011
Salary and employee benefits	**$ 9**	$ 9
Termination benefits	**6**	—
Share-based payments [1]	**(6)**	11
	$ 9	$ 20

(1) Includes changes in the value of Restricted rights and non-cash charges related to the Option Plan, CSRIP, DSU and TURIP for key management personnel.

22. Supplemental Items

In the consolidated financial statements, compensation costs are included in both operating and general and administrative expenses. For 2012, employee compensation costs of $139 million (2011—$127 million) were included in operating costs and $176 million (2011—$129 million) were included in general and administrative expenses.

Exhibit 99.4

SUPPLEMENTARY OIL AND GAS INFORMATION—(UNAUDITED)

The disclosures contained in this section provide oil and gas information in accordance with the U.S. standard, "Extractive Industries —Oil and Gas". Penn West's financial reporting is prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board.

NET PROVED OIL AND NATURAL GAS RESERVES

Penn West engaged independent qualified reserve evaluators, GLJ Petroleum Consultants Ltd. ("GLJ") and Sproule Associates Ltd. ("Sproule"), to evaluate Penn West's proved developed and proved undeveloped oil and natural gas reserves or to audit Penn West's evaluation thereof. As at December 31, 2012, substantially all of Penn West's oil and natural gas reserves are located in Canada with less than one percent of our proved reserves located in the United States. The changes in our net proved reserve quantities are outlined below.

Net reserves include Penn West's remaining working interest and royalty reserves, less all Crown, freehold, and overriding royalties and other interests that are not owned by Penn West.

Proved reserves are those estimated quantities of crude oil, natural gas and natural gas liquids that can be estimated with a high degree of certainty to be economically recoverable under existing economic and operating conditions.

Proved developed reserves are those proved 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 to put the reserves on production. Proved developed reserves may be subdivided into producing and non-producing.

Proved undeveloped reserves are those reserves that are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Penn West cautions users of this information as the process of estimating crude oil and natural gas reserves is subject to a level of uncertainty. The reserves are based on economic and operating conditions; therefore, changes can be made to future assessments as a result of a number of factors, which can include new technology, changing economic conditions and development activity.

YEAR ENDED DECEMBER 31, 2012
CONSTANT PRICES AND COSTS

Net Proved Developed and Proved Undeveloped Reserves [1]	Light and Medium Oil (mmbbl)	Heavy Oil (mmbbl)	Natural Gas (bcf)	Natural Gas Liquids (mmbbl)	Barrels of Oil Equivalent (mmboe)
December 31, 2011	254	47	630	20	427
Extensions & Discoveries	5	—	15	—	8
Improved Recovery	21	3	11	1	27
Technical Revisions	—	2	(20)	(1)	(3)
Acquisitions	—	—	—	—	—
Dispositions	(44)	(4)	(9)	(1)	(50)
Production	(23)	(5)	(101)	(3)	(48)
Change for the year	(41)	(4)	(104)	(4)	(66)
December 31, 2012	214	42	526	17	360
Developed	148	40	463	15	279
Undeveloped	66	2	63	2	81
Total [2]	214	42	526	17	360

(1) Columns may not add due to rounding.
(2) Penn West does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

YEAR ENDED DECEMBER 31, 2011
CONSTANT PRICES AND COSTS

Net Proved Developed and Proved Undeveloped Reserves [1]	Light and Medium Oil (mmbbl)	Heavy Oil (mmbbl)	Natural Gas (bcf)	Natural Gas Liquids (mmbbl)	Barrels of Oil Equivalent (mmboe)
December 31, 2010	232	47	685	17	410
Extensions & Discoveries	15	—	31	2	22
Improved Recovery	29	1	41	3	40
Technical Revisions	3	4	(13)	1	6
Acquisitions	4	—	10	—	6
Dispositions	(5)	—	(14)	—	(8)
Production	(22)	(6)	(111)	(3)	(49)
Change for the year	24	(1)	(56)	3	17
December 31, 2011	254	47	630	20	427
Developed	186	45	560	17	341
Undeveloped	68	2	70	3	86
Total [2]	254	47	630	20	427

(1) Columns may not add due to rounding.
(2) Penn West does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

CAPITALIZED COSTS

As at December 31, ($CAD millions)	2012	2011
Proved oil and gas properties	$19,798	$20,235
Unproved oil and gas properties	609	418
Total capitalized costs	20,407	20,653
Accumulated depletion and depreciation	(8,906)	(8,342)
Net capitalized costs	$11,501	$12,311

COSTS INCURRED

For the years ended December 31, ($CAD millions)	2012	2011
Property acquisition (disposition) costs [1]		
Proved oil and gas properties—acquisitions	$ 52	$ 138
Proved oil and gas properties—dispositions	(1,667)	(404)
Unproved oil and gas properties	37	181
Exploration costs [2]	241	330
Development costs [3]	1,595	1,417
Joint venture, carried capital	(137)	(107)
Capital expenditures	121	1,555
Corporate acquisitions	—	286
Total expenditures	$ 121	$ 1,841

(1) Acquisitions are net of disposition of properties.
(2) Cost of geological and geophysical capital expenditures and costs on exploratory plays.
(3) Includes equipping and facilities capital expenditures.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN

The standardized measure of discounted future net cash flows is based on estimates made or audited by GLJ and Sproule of net proved reserves. Future cash inflows are computed based on constant prices and cost assumptions from annual future production of proved crude oil and natural gas reserves. Future development and production costs are based on constant price assumptions and assume the continuation of existing economic conditions. Constant prices are calculated as the average of the first day prices of each month for the prior 12-month period calendar period. Deferred income taxes are calculated by applying statutory income tax rates in effect at the end of the fiscal period. Penn West is currently not cash taxable. The standardized measure of discounted future net cash flows is computed using a 10 percent discount factor.

Penn West cautions users of this information that the discounted future net cash flows relating to proved oil and gas reserves are neither an indication of the fair market value of our oil and gas properties, nor of the future net cash flows expected to be generated from such properties. The discounted future cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent is arbitrary and may not reflect applicable future interest rates.

($CAD millions)	2012	2011
Future cash inflows	$ 23,141	$ 30,815
Future production costs	(10,359)	(12,287)
Future development costs	(2,372)	(2,350)
Undiscounted pre-tax cash flows	10,410	16,178
Deferred income taxes (1)	(1,242)	(2,463)
Future net cash flows	9,168	13,715
Less 10% annual discount factor	(4,054)	(5,080)
Standardized measure of discounted future net cash flows	$ 5,114	$ 8,635

(1) Penn West is currently not cash taxable.

($CAD millions)	2012	2011
Estimated future net revenue at beginning of year	$ 8,635	$ 6,081
Oil and gas sales during period net of production costs and royalties (1)	(1,640)	(1,878)
Changes due to prices and royalties related to forecast production (2)	(1,865)	2,068
Development costs during the period (3)	1,736	1,821
Changes in forecast development costs (4)	(1,387)	(1,774)
Changes resulting from extensions and improved recovery (5)	526	1,256
Changes resulting from acquisitions of reserves (5)	2	115
Changes resulting from dispositions of reserves (5)	(1,221)	(164)
Accretion of discount (6)	864	608
Net change in income tax (7)	636	(917)
Changes resulting from technical reserves revisions	(49)	118
All other changes (8)	(726)	1,300
Estimated future net revenue at end of year	$ 5,510	$ 8,635

(1) Company actual before income taxes, excluding general and administrative expenses.
(2) The impact of changes in prices and other economic factors on future net revenue.
(3) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.
(4) The change in forecast development costs.
(5) End of period net present value of the related reserves.
(6) Estimated as 10 percent of the beginning of period net present value.
(7) The difference between forecast income taxes at beginning of period and the actual taxes for the period plus forecast income taxes at the end of period.
(8) Includes changes due to revised production profiles, development timing, operating costs, royalty rates and actual prices received versus forecast, etc.

Exhibit 99.5

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934

I, Murray R. Nunns, certify that:

1. I have reviewed this annual report on Form 40-F of Penn West Petroleum Ltd.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;
4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:
    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and
5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: March 14, 2013

/s/ Murray R. Nunns

Murray R. Nunns
President & Chief Executive Officer

Exhibit 99.6

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934

I, Todd H. Takeyasu, certify that:

1. I have reviewed this annual report on Form 40-F of Penn West Petroleum Ltd.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;
4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:
    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
    (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
    (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and
5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: March 14, 2013

/s/ Todd H. Takeyasu

Todd H. Takeyasu
Executive Vice-President and Chief Financial Officer

Exhibit 99.7

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn West Petroleum Ltd. (the "Company") on Form 40-F for the year ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Murray R. Nunns, President & Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ Murray R. Nunns
Murray R. Nunns
President & Chief Executive Officer

March 14, 2013

Exhibit 99.8

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Penn West Petroleum Ltd. (the "Company") on Form 40-F for the year ended December 31, 2012, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Todd H. Takeyasu, Executive Vice President and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

By: /s/ Todd H. Takeyasu
Todd H. Takeyasu
Executive Vice-President and Chief Financial Officer

March 14, 2013

Exhibit 99.9



KPMG LLP
205-5th Avenue SW
Suite 2700, Bow Valley Square 2
Calgary AB
T2P 4B9

Telephone (403) 691-8000
Fax (403) 691-8008
www.kpmg.ca

Consent of Independent Registered Public Accounting Firm

To the Board of Directors of Penn West Petroleum Ltd.

We consent to the incorporation by reference in the registration statement (No. 33-171675) on Form F-3 of Penn West Petroleum Ltd. of our reports dated March 13, 2013, on:

- the consolidated financial statements which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011, the consolidated statements of income, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information; and
- the effectiveness of internal control over financial reporting as of December 31, 2012,

which reports appear in the annual report on Form 40-F of Penn West Petroleum Ltd. for the year ended December 31, 2012, and further consent to the use of such reports in such annual report on Form 40-F.

KPMG LLP

Chartered Accountants
March 14, 2013
Calgary, Canada

KPMG LLP is a Canadian limited liability partnership and a member firm of the KPMG network of independent member firms affiliated with KPMG International Cooperative ("KPMG International"), a Swiss entity. KPMG Canada provides services to KPMG LLP.

KPMG Confidential

Exhibit 99.10

GLJ Petroleum Consultants

Principal Officers:
Keith M. Braaten, P. Eng.
President & CEO
Jodi L. Anhorn, P. Eng.
Executive Vice President & COO

Officers/Vice Presidents:
Terry L. Aarsby, P. Eng.
Caralyn P. Bennett, P. Eng.
Leonard L. Herchen, P. Eng.
Myron J. Hladyshevsky, P. Eng.
Bryan M. Joa, P. Eng.
Mark Jobin, P. Geol.
John E. Keith, P. Eng.
John H. Stiiling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

Penn West Petroleum Ltd.
200, 207—9th Avenue SW
Calgary, AB T2P 1K3

We refer to: (i) our report dated January 31, 2013 and effective as of December 31, 2012, evaluating the crude oil, natural gas and natural gas liquids reserves and the net present value of future net revenue attributable to certain of the oil and natural gas properties of Penn West Petroleum Ltd. ("**Penn West**") effective as at December 31, 2012 and (ii) our report dated February 5, 2013 and effective as of December 31, 2012 consolidating the independent evaluations and audit of Penn West's oil and natural gas properties as at December 31, 2012 prepared in separate reports by GLJ Petroleum Consultants Ltd. and Sproule Associates Limited (collectively, the "**Reports**"). We hereby consent to the use and reference to our name and the Reports, and the information derived from the Reports, as described or incorporated by reference in: (i) Penn West's Annual Report on Form 40-F for the year ended December 31, 2012; and (ii) Penn West's Registration Statement on Form F-3 (No. 333-171675), filed or to be filed with the United States Securities and Exchange Commission.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

/s/ Bryan M. Joa
Bryan M. Joa, P. Eng.
Vice President

Dated: March 7, 2013
Calgary, Alberta
CANADA

Exhibit 99.11

R.K. MacLeod*, B.S., P.Eng., *President*
H.J. Helwerda*, B.Sc., P.Eng., FEC, *Executive V.P.*
J.L. Chipperfield*, B.Sc., P.Geol., *Senior V.P.*
D.W.C. Ho*, B.A.Sc., P.Eng., *V.P., Engineering*
G.D. Robinson*, B.Sc., P.Eng., *V.P., Engineering*
D.J. Carsted*, CD, B.Sc., P.Geol., *V.P., Geoscience*
C.P. Six, B.Sc., P.Eng., *V.P., Engineering*
K.P. McDonald, B.Comm., C.A., *CFO,*
Corporate Secretary

**Directors*

Ref.: 1772

March 6, 2013

Penn West Petroleum Ltd.
200, 207 Ninth Avenue SW
Calgary, AB T2P 1K3

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We refer to our report dated February 22, 2013 and effective as of December 31, 2012, evaluating the crude oil, natural gas and natural gas liquids reserves and the net present value of future net revenue attributable to certain of the oil and natural gas assets of Penn West Petroleum Ltd. ("**Penn West**") effective as at December 31, 2012 (the " **Report**").

We hereby consent to the use and reference to our name and the Report, and the information derived from the Report, as described or incorporated by reference in: (i) Penn West's Annual Report on Form 40-F for the year ended December 31, 2012; and (ii) Penn West's Registration Statement on Form F-3 (No. 333-171675), filed or to be filed with the United States Securities and Exchange Commission.

Sincerely,

SPROULE ASSOCIATES LIMITED

/s/ Gary R. Finnis
Gary R. Finnis, P.Eng.
Supervisor, Engineering and Partner

Enclosure(s)
GRF:aml
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