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, 2011

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: 471,372,730

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, 2011;

(b) Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2011;

(c) Consolidated Financial Statements for the fiscal year ended December 31, 2011, prepared under International Financial Reporting Standards as issued by the International Accounting Standards Board; and

(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, 2011, 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 are 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, 2011. 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, 2011.

The effectiveness of Penn West's internal control over financial reporting as at December 31, 2011 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 Consolidated Financial Statements for the fiscal year ended December 31, 2011, 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 Consolidated Financial Statements for the fiscal year ended December 31, 2011, 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, 2011 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 2011 and 2010:

(CDN$)	**2011**	**2010**
Audit Fees	1,092,500	1,120,000
Audit-Related Fees	165,000	115,000
Tax Fees	—	—
All Other Fees	130,000	125,000
Total	1,387,500	1,360,000

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 Penn West's portion of fees for the Peace River Oil Partnership audit.

Audit-Related Fees. Audit-related fees consist of consultations related to International Financial Reporting Standards and matters related to the corporate acquisitions completed in 2011 and 2010.

Tax fees. None

All Other fees. All other fees primarily consisted of French translation services.

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 does not have any off-balance sheet financing arrangements that have, or are reasonably likely to have, a material effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Tabular Disclosure of Contractual Obligations.

(CDN$ millions)		Payment due by period			
Contractual Obligations	**Total**	**Less than 1 Year**	**1 to 3 Years**	**3 to 5 Years**	**More than 5 Years**
Transportation	411	27	72	81	231
Power infrastructure	106	32	30	30	14
Drilling rigs	102	26	48	26	2
Purchase obligations (1)	54	13	24	12	5
Office lease (2)	792	68	126	119	479
Long-term debt (3)(4)	3,219	—	66	1,725	1,428
Decommissioning liability (5)	3,381	75	150	150	3,006
Total	**8,065**	**241**	**516**	**2,143**	**5,165**

(1) These amounts represent estimated commitments of $40 million for CO2 purchases and $14 million for processing fees related to interests in the Weyburn Unit.
(2) Future office lease commitments will be reduced by sublease recoveries of $434 million.
(3) Penn West's syndicated bank facility is due for renewal on June 26, 2015. 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, Shirley A. McClellan and Frank Potter.

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.

Membership on Multiple Audit Committees

Section 303A.07 of the NYSE's Listed Company Manual requires that if an audit committee member simultaneously serves on the audit committees of more than three public companies, and if the listed company does not limit the number of audit committees on which its audit committee members may serve to three or less, the board of directors of the listed company must determine that such simultaneous service would not impair the ability of the audit committee member to effectively serve on the listed company's audit committee, and must publicly disclose such determination. James C. Smith and Frank Potter, members of Penn West's audit committee, serve on the audit committees of more than three public companies. Penn West's board of directors has determined that such simultaneous service would not impair Mr. Smith's or Mr. Potter's ability to effectively serve on Penn West's audit committee.

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 16, 2012.

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, 2011
99.2	Management's Discussion and Analysis of Financial Condition and Results of Operations for the fiscal year ended December 31, 2011
99.3	Consolidated Financial Statements for the fiscal year ended December 31, 2011
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, 2011

March 15, 2012

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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.

"**2007 Senior Notes**" means our notes in the aggregate principal amount of US$475 million issued on May 31, 2007, which consist of US$160 million principal amount of 5.68 percent notes due in 2015, US$155 million principal amount of 5.80 percent notes due in 2017, US$140 million principal amount of 5.90 percent notes due in 2019 and US$20 million principal amount of 6.05 percent notes due in 2022. The 2007 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2008 Senior Notes**" means our notes in the aggregate principal amount of US$480 million and Cdn$30 million issued on May 29, 2008, which consist of US$153 million principal amount of 6.12 percent notes due in 2016, US$278 million principal amount of 6.30 percent notes due in 2018, Cdn$30 million principal amount of 6.16 percent notes due in 2018 and US$49 million principal amount of 6.40 percent notes due in 2020. The 2008 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2008 Senior Notes (Pounds Sterling)**" means our notes in the aggregate principal amount of £57 million issued on July 31, 2008, which consist of £57 million principal amount of 7.78 percent notes due in 2018. These notes bear interest at 7.78 percent in Pounds Sterling under the note purchase agreement, however, contracts were entered into that fix the interest rate at 6.95 percent in Canadian dollars. The 2008 Senior Notes (Pounds Sterling) are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2009 Senior Notes**" means our notes in the aggregate principal amount of US$154 million, £20 million, €10 million and Cdn$5 million issued on May 5, 2009, which consist of Cdn$5 million principal amount of 7.58 percent notes due in 2014, US$50 million principal amount of 8.29 percent notes due in 2014, US$35 million principal amount of 8.89 percent notes due in 2016, US$35 million principal amount of 8.89 percent notes due between 2013 and 2019, £20 million principal amount of 9.49 percent notes due in 2019, €10 million principal amount of 9.52 percent notes due in 2019 and US$34 million principal amount of 9.32 percent notes due in 2019. Contracts were entered into that fix the interest on the Pounds Sterling tranche of notes (9.49 percent in Pounds Sterling under the note purchase agreement) and Euro tranche of notes (9.52 percent in Euros under the note purchase agreement) in Canadian dollars at 9.15 percent and 9.22 percent, respectively. The 2009 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2010 Q1 Senior Notes**" means our notes in the aggregate principal amount of US$250 million and Cdn$50 million issued on March 16, 2010, which consist 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. The 2010 Q1 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2010 Q4 Senior Notes**" means our notes in the aggregate principal amount of US$170 million and Cdn$60 million issued on December 2, 2010 and January 4, 2011, which consist 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. The 2010 Q4 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**2011 Senior Notes**" means our notes in the aggregate principal amount of US$105 million and Cdn$30 million issued on November 30, 2011, which consist 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. The 2011 Senior Notes are guaranteed, unsecured and rank equally with our bank credit facilities and our other Senior Notes.

"**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.

"**Canadian GAAP**" means Canadian generally accepted accounting principles determined with reference to Part V of the Handbook, which contains the accounting principles applicable to public enterprises for periods relating to financial years beginning before January 1, 2011 (i.e., before the adoption of IFRS as Canadian GAAP for public enterprises).

"**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, 2011 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 February 8, 2012 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, 2011.

"**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**" 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 amalgamated under the ABCA pursuant to the Corporate Conversion 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, collectively, our 2007 Senior Notes, our 2008 Senior Notes, our 2008 Senior Notes (Pounds Sterling), our 2009 Senior Notes, our 2010 Q1 Senior Notes, our 2010 Q4 Senior Notes and our 2011 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 6, 2012 evaluating approximately 34 percent and auditing approximately 18 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, 2011.

"**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.

"**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 15, 2012, the exchange rate based on the noon rate as reported by the Bank of Canada, was Cdn$1.00 equals US$1.0072.

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, 2011 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 undeveloped land and unproved properties held, owned, acquired or disposed by us, or in respect of which we have an interest, refer to undeveloped land or unproved properties in respect of which we have a lease or other contractual right to explore for, develop, exploit and produce hydrocarbons underlying such undeveloped land or unproved 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 dividend policy, including the amount of dividends that we intend to pay, the proposed timing of such payments, and the factors that may affect the amount of dividends that we pay; 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 expectations regarding the operational and financial impact that climate change regulations in the jurisdictions in which we operate will have on us; our intention and ability to reduce our emissions intensity, improve energy efficiency and develop carbon dioxide injection and sequestration technology and infrastructure; 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 2012 and beyond, including our anticipated 2012 capital expenditure levels in each of our key resource plays and the key elements of our 2012 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 2012; our production volume estimates for 2012; 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; 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 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; and our ability to add production and reserves through our development and exploitation activities. 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; 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 historical dispositions, acquisitions, joint ventures and partnerships discussed herein; 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, 2011.

PENN WEST PETROLEUM LTD.

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 SW, Calgary, Alberta, T2P 1K3.

Corporate Conversion

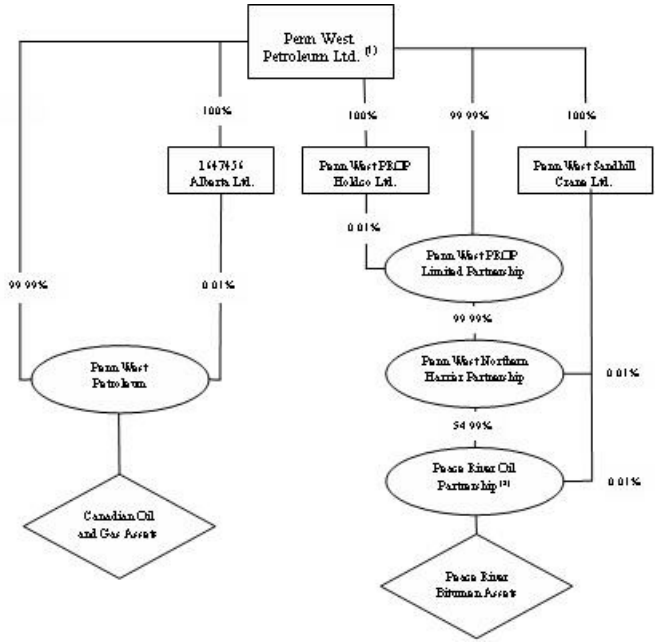
The Corporate Conversion was completed on January 1, 2011 and resulted in the reorganization of Penn West Trust (an income trust) into Penn West (a corporation) and the unitholders of Penn West Trust becoming the Shareholders of Penn West. Penn West and its Subsidiaries now carry on the business formerly 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 of Penn West Trust and Penn West 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) Penn West was formed pursuant to the amalgamation of Penn West Petroleum Ltd., Canetic Tech Holdco Inc., Penn West Santiago Ltd., Sifton Energy Inc. and Trocana Resources Inc. on January 1, 2012.
(2) The remaining 45% interest in Peace River Oil Partnership is owned by Winter Spark Resources, Inc., an affiliate of China Investment Corporation.
(3) 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, 2011, we had approximately 2,170 head office and field 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, 2011.

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, 2009

Public Offering of Trust Units

On February 5, 2009, Penn West completed a public offering of 17.7 million Trust Units at a price of $14.10 per Trust Unit for aggregate gross proceeds of approximately $250 million. The net proceeds of the offering were used by Penn West to partially fund capital expenditures and to reduce its indebtedness. The Trust Units were issued by way of a prospectus supplement that was filed with securities regulatory authorities in Canada and the U.S. under Penn West's short form base shelf prospectus dated June 13, 2008 and SEC registration statement on Form F-10, which were previously filed with securities regulatory authorities across Canada and with the SEC under the multi-jurisdictional disclosure system.

Reece Acquisition

Effective April 30, 2009, Penn West completed the acquisition of Reece Energy Exploration Corp. (" **Reece**") pursuant to a plan of arrangement completed under the ABCA. Pursuant to the acquisition, Penn West issued 0.125 of a Trust Unit for each one common share of Reece acquired. An aggregate of approximately 4.7 million Trust Units were issued. As a result of the acquisition, Penn West added production of approximately 1,900 boe per day and approximately 67,000 net acres of undeveloped land. Penn West also assumed approximately $42 million of debt and working capital deficit in connection with the acquisition.

Private Placement of 2009 Senior Notes

Effective May 5, 2009, Penn West completed the private placement of the 2009 Senior Notes, which consisted of the issuance of Cdn$5 million principal amount of 7.58 percent notes due in 2014, US$50 million principal amount of 8.29 percent notes due in 2014, US$35 million principal amount of 8.89 percent notes due in 2016, US$35 million principal amount of 8.89 percent notes due between 2013 and 2019, £20 million principal amount of 9.49 percent notes due in 2019, €10 million principal amount of 9.52 percent notes due in 2019 and US$34 million principal amount of 9.32 percent notes due in 2019. The 2009 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.

November 2009 Asset Disposition

On November 30, 2009, Penn West completed the disposition (the "**November 2009 Asset Disposition**") of certain heavy oil assets located primarily in the Lloydminster area of Alberta and Saskatchewan. Pursuant to the transaction, Penn West disposed of approximately 6,000 boe per day of production and approximately 10,000 net acres of undeveloped land. The proceeds of the November 2009 Asset Disposition were used to repay a portion of the indebtedness outstanding under our bank credit facilities.

Other Acquisitions and Dispositions

Including the November 2009 Asset Disposition, Penn West completed property dispositions, net of acquisitions, of $369 million in 2009.

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 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 2010 Q1 Senior Notes

Effective March 16, 2010, Penn West completed the private placement of the 2010 Q1 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. The 2010 Q1 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.

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.

Other Acquisitions and Dispositions

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 2010 Q4 Senior Notes

On December 2, 2010 and January 4, 2011, Penn West completed the private placement of the 2010 Q4 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. The 2010 Q4 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.

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. In addition, Hilary Foulkes, the Executive Vice-President, Business Development of Penn West, was appointed Executive Vice President and Chief Operating 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 now has 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 2011 Senior Notes

On November 30, 2011, Penn West completed the private placement of the 2011 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. The 2011 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.

Acquisitions and Dispositions

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

2012 Developments

Acquisitions and Dispositions

As at March 15, 2012, Penn West has completed property dispositions, net of acquisitions, of approximately $340 million in 2012.

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 15, 2012, 472,900,258 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 brief 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, unsecured and rank equally with our credit facilities.

Credit Facility

Penn West has an unsecured, revolving credit facility with a four-year term ending June 26, 2015 with a syndicate of Canadian and international banks. The credit facility has an aggregate borrowing limit of $2.75 billion. As at March 15, 2012, approximately $1.5 billion had been borrowed under the credit facility.

Additional Information

For additional information regarding our Senior Notes and our credit facility, see Notes 10 and 20 (collectively, the " **Notes**") to our audited consolidated financial statements for the year ended December 31, 2011, 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 Notes 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 sets forth the name, province/state 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/State 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 Guide Exploration Ltd. (“Guide”), a public oil and natural gas company, since August 2011 and Chief Executive Officer of Guide 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[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).
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[1][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. Prior thereto, Deputy Premier of the Province of Alberta from 2001 to 2007 and Minister of Finance of the Province of Alberta from 2004 to 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.
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.

Name, Province/State and Country of Residence	Positions and Offices Held with Penn West	Principal Occupations during the Five Preceding Years
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. Prior thereto, Vice President, Operations of the operating subsidiary of Canetic Resources Trust.
Hilary Foulkes Alberta, Canada	Executive Vice President and Chief Operating Officer	Executive Vice President and Chief Operating Officer of Penn West since August 2011. Prior thereto, Executive Vice President, Business Development of Penn West from January 2011 to August 2011. Prior thereto, Senior Vice-President, Business Development of Penn West from April 2008 to January 2011. Prior thereto, a Managing Director with Scotia Waterous, an investment banking firm.
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.
Thane A.E. Jensen Alberta, Canada	Senior Vice President, Operations	Senior Vice President, Operations of Penn West since November 2008. Prior thereto, Senior Vice President, Exploration and Development of 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. Prior thereto, Senior Vice President, Stakeholder Relations of Penn West from January 2008 to February 2008. Prior thereto, Vice President, Land and Legal of Penn West.
David W. Middleton Alberta, Canada	Executive Vice President, Managing Director, Peace River Oil Partnership	Executive Vice President, Managing Director, Peace River Oil Partnership for Penn West since June 2010. 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. Prior thereto, Executive Vice President and Chief Operating Officer of Penn West from June 2005 to February 2008.

Name, Province/State and Country of Residence	Positions and Offices Held with Penn West	Principal Occupations during the Five Preceding Years
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. Prior thereto, General Manager, Oil Sands at Husky Energy Inc.
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. Prior thereto, Senior Vice President, Finance – Treasury of Penn West from January 2008 to February 2008. Prior thereto, Senior Vice President and Chief Financial Officer of Penn West.
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 Trafalger Energy Ltd., a public oil and natural gas company now known 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 15, 2012, the directors and executive officers of Penn West, as a group, beneficially owned, or controlled or directed, directly or indirectly, approximately one million Common Shares, or less than one percent of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

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

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

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

Daryl Gilbert was a director of Globel Direct, Inc., which was subject to a cease trade order issued by the British Columbia Securities Commission on November 20, 2002 and the Alberta Securities Commission on November 22, 2002 for delay in filing financial statements. The required financial statements were filed and the cease trade orders were revoked effective December 23, 2002. 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. 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 (nor any personal holding company of any of such persons), or a shareholder holding a sufficient number of securities of Penn West to affect materially the control of Penn West:

(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 (nor any personal holding company of any of such persons), or a shareholder holding a sufficient number of securities of Penn West to affect materially the control of Penn West, 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 or officer of any entity engaged in the oil and gas business 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

The members of the Audit Committee are James C. Smith, Chairman, and James E. Allard, Shirley A. McClellan 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 the past 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 ten 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.

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. 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.

Shirley A. McClellan

Mrs. McClellan is a Distinguished Scholar in Residence at the University of Alberta for the Faculties of Agriculture and Rural Economy and the School of Business. She lectures primarily in Rural Economy and in the School of Business. Mrs. McClellan brings to Penn West the experience gained over 20 years of distinguished service to the Province of Alberta. Her career included the offices of Deputy Premier of Alberta from 2001 to 2007, Minister of Finance of Alberta from 2004 to 2007 and Chair of the Treasury Board and Vice-Chair of the Agenda and Priorities Committee of the Government of Alberta. Mrs. McClellan served a total of six terms as a Member of the Alberta Legislative Assembly representing the constituency of Drumheller-Stettler. Over this time period, she held numerous other portfolios, including Minister of Agriculture, Food and Rural Development, Minister of International and Intergovernmental Relations, Minister of Community Development, and Minister of Health.

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 paid by Penn West to KPMG LLP for external audit and other services during the periods indicated.

Year	Audit Fees[1] ($)	Audit-Related Fees[2] ($)	Tax Fees[3] ($)	All Other Fees[4] ($)
2011	1,092,500	165,000	—	130,000
2010	1,120,000	115,000	—	125,000

Notes:

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

(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 consultations related to International Financial Reporting Standards and matters related to the corporate acquisitions completed in 2011 and 2010.

(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.

(4) The aggregate fees billed in each of the last two fiscal years by our external auditor for products and services not included under the headings "Audit Fees", "Audit Related Fees" and "Tax Fees". The services comprising the fees disclosed under this category principally consisted of French translation services.

Reliance on Exemptions

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

Audit Committee Oversight

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

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*".

Effective from January 1, 2011, all dividends paid on our Common Shares 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 years ended December 31, 2010 and December 31, 2009, respectively, Penn West Trust declared payable the following amount of cash distributions per Trust Unit:

Month	2010 Distributions Declared Payable ($)	2009 Distributions Declared Payable ($)
January	0.15	0.23
February	0.15	0.23
March	0.15	0.23
April	0.15	0.15
May	0.15	0.15
June	0.15	0.15
July	0.15	0.15
August	0.15	0.15
September	0.09	0.15
October	0.09	0.15
November	0.09	0.15
December	0.09	0.15
Total	1.56	2.04

Note:

(1) The Corporate Conversion was completed on January 1, 2011. This table references cash distributions declared payable on the Trust Units during the two financial years ended December 31, 2010 and December 31, 2009, respectively, prior to the completion of the Corporate Conversion.

Dividends Declared Payable to Shareholders of Penn West

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

Quarter	2011 Dividends Declared Payable ($)
First Quarter	0.27
Second Quarter	0.27
Third Quarter	0.27
Fourth Quarter	0.27
Total	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 financial year ended December 31, 2011 following the completion of the Corporate Conversion.

MARKET FOR SECURITIES

Common Shares and Trust Units

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 Trust Units and the Common Shares in 2011 as reported by the TSX and the NYSE.

	TSX		
Period	Trust Unit / Common Share price ($) High	Trust Unit / Common Share price ($) Low	Volume
January	27.59	23.95	33,510,152
February	28.20	25.47	23,033,719
March	28.10	24.06	22,930,516
April	27.11	23.65	15,785,506
May	25.34	21.84	26,261,134
June	25.29	21.74	23,282,607
July	22.81	20.86	19,965,360
August	21.28	17.05	34,986,332
September	18.45	15.33	26,111,066
October	18.84	13.22	39,499,988
November	18.82	16.51	25,943,950
December	20.89	18.25	29,523,890

	NYSE		
Period	Common Share price ($US) High	Common Share price ($US) Low	Volume
January	27.49	24.22	33,577,154
February	28.90	25.70	41,013,958
March	28.55	26.22	37,770,631
April	28.01	25.19	28,964,106
May	26.06	23.53	52,599,090
June	25.61	22.17	40,136,988
July	23.62	22.19	29,891,168
August	22.29	17.37	65,546,428
September	18.44	14.77	43,139,410
October	18.77	13.60	60,326,584
November	18.49	16.05	48,197,121
December	20.31	17.84	46,065,977

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 negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand, however, they may be influenced by regional transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the 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.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. 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 governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

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 oil sands projects and crude oil, natural gas liquids, sulphur and natural gas production. 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 sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and respective market prices for the four categories of conventional oil which include light oil, medium oil, heavy oil and ultra-heavy oil. 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 $85 per barrel 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 the 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 existing royalty regimes.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production 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 IETP has been extended for approved projects for costs incurred up to December 31, 2006.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 and are intended 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 new 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. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5 percent royalty rate for eligible new wells for the first 12 productive months or until the regulated "volume cap" was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

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 (" **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 as an incentive for the production and marketing of natural gas which might otherwise have been flared.

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. For natural gas, the freehold production tax 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.

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

- *Summer Royalty Credit Program* providing a royalty credit of 10 percent of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;
- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23 percent of 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;
- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;
- *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 with a spud date after November 30, 2003;
- *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 royalty reductions for low productivity 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 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 11.5 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 (the " **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 improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15 percent and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

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 classified as "**heavy oil**", "**southwest designated oil**" or "**non-heavy oil other than southwest designated oil**". The heavy oil and southwest designated oil categories have geographical restrictions outlining specific boundaries that apply on oil production. 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 new oil (not classified as either third tier oil or fourth tier oil). 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.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional 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

vintage of the natural gas. Like conventional oil, natural gas may be classified as "**non-associated gas**" or "**associated gas**" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. 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.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* , which replaced the *Freehold Oil and Gas Production Tax Act* with the intention of facilitating the more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

As with conventional oil production, base prices 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 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 and freehold tax rates 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);
- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates 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 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 or within certain formations);
- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells;
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre-payout and post-payout;
- *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 enhanced oil recovery projects

pre-payout and 20 percent post-payout and a freehold production tax of nil on operating income from enhanced oil recovery projects pre-payout and 8 percent post-payout; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* 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.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate (" **RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

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 is set to commence on July 1, 2012 for new wells and facilities licensed on or after such date, and to 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.

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

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments, with the exception of Manitoba, where approximately 80 percent of the crude oil and natural gas rights in the southwestern portion of the province are privately owned. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to exploration reservations and leases, licences and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned 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's policy of deep rights reversion was expanded 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 reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, 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, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in the spring of 2012.

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 requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial 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 material fines and penalties.

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 29, 2011, the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the " **Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas in the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP, and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol (" **Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005, although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets 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.

The Updated Action Plan makes a distinction between "**Existing Facilities**" and "**New Facilities**". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18 percent below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2 percent. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25 percent or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2 percent emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be: (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d per company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, which is discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets.

1. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70 percent in 2010 to nil in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.
2. The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.
3. Under the Updated Action Plan, regulated entities would also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10 percent of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations. However, in light of Canada's recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.
4. Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

In December 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements, wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from the coal-fired generation of electricity have been proposed to date. Furthermore, 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, if any, the proposals contained in the Updated Action Plan will be implemented.

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 will 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 and it is unclear whether the EPA will also miss the finalized regulations deadline.

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 (the "**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.

Facilities in Alberta that have GHG emissions between 50,000 and 100,000 tonnes per year are required to report under the *Specified Gas Reporting Regulation*. Penn West anticipates it will have no operated facility that will be required to report under these regulations. As at the date hereof, we do not believe that our financial obligations associated with such reporting obligations 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 $25 per tonne of CO_2 equivalent. It is scheduled to increase to $30 per tonne of CO_2 equivalent on July 31, 2012. 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 2011, 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.

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. 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. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010 new reporting regulations (the "**Cap and Trade Regulations**") came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage.

Penn West's linear facility in British Columbia is covered by the Cap and Trade Regulations. We anticipate that we will have one facility over the 25,000 tonne threshold, two facilities 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 Regulations. 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 Regulations 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% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

Manitoba

The Government of Manitoba has indicated its intention to commence public consultations with respect to the development of a cap and trade system to reduce GHG emissions. No legislation with respect to an emissions reduction regime is currently in effect in Manitoba.

Penn West and the Environment

Penn West understands its responsibilities of 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 2012, includes measures to remediate potential contaminant sources, reclaim spill sites and abandon unproductive wells and shut-in facilities.

Alberta and British Columbia 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 four 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 CAPP, 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. In the meantime, Penn West will continue its current activities to reduce its emissions intensity, improve energy efficiency, and develop CO_2 injection and sequestration technology and infrastructure.

Penn West provides additional information on GHGs in the annual international Carbon Disclosure Project, which details significantly more information regarding emissions, business strategy, governance, and potential risks for those who are interested.

In 2010, Penn West completed CO_2 injection pilot testing in the Pembina and Swan Hills areas of Alberta and continued to monitor production response in 2011. Both pilot projects provided valuable information which could lead to additional enhanced oil recovery projects in the future. During 2011, Penn West continued discussions with several parties regarding the supply and delivery of commercial quantities of CO_2 to its fields.

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. Shareholders and potential Shareholders 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.

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:

- 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 availability of transportation infrastructure;
- 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 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.

The marketability and price of oil and natural gas that may be acquired or discovered by us are and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil and natural gas. 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 2011, our production levels (and as a result our revenues) were at times 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 plagued our operations in 2011 will not occur again in 2012 or subsequent years 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 conventional 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 may manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges. If 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 decrease in the amount of cash dividends paid to Shareholders, which would 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;
- ultimate estimated reserve recovery;
- 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.

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. We may also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits regulated by the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those conducted by us. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or 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.

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.

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.

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

Oil and natural gas operations (including exploration, production, pricing, marketing and transportation operations) are subject to extensive controls and regulations imposed by various levels of government that may be changed or amended from time to time. We have no control over these changes and amendments and the impact that they may have on us, and any such impact could be material and adverse. See “Industry Conditions”.

Our operations require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at our projects.

Acquiring, exploring for and developing 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.

Acquiring, exploring for and developing 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;
- blowouts, 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.

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. Losses resulting from the occurrence of these risks could have a material adverse impact on us. 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 pipeline capacity;
- 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;
- 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.

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. 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 have control of. 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.

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 affect 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.

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 also 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 operating activities 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.

Additionally, the reduced "Qualified Dividend" rate of 15 percent tax which has applied to our distributions under current U.S. tax laws is scheduled to expire at the end of 2012 and there is no assurance that this reduced tax rate will be renewed by the U.S. government at such time.

We use conventional recovery methods, such as horizontal multi-stage fracture 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 greenhouse gas 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 carbon dioxide 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.

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.

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

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

The 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 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".

Our Common Shares may from time to time trade at a price that is less than our net asset value per Common Share.

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.

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.

If oil and gas prices decline, we may be required under applicable accounting standards to write down the value of our assets.

Historically, Canadian GAAP required that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in our consolidated financial statements. Under Canadian GAAP, the amounts at which petroleum and natural gas property and equipment were carried as net assets on the balance sheet were subject to a cost-recovery or "ceiling" test, which was based in part upon estimated future net revenues from reserves. If net capitalized costs exceeded the estimated recoverable amounts, we would have to charge the amount of the excess to income. A decline in the net value of oil and natural gas properties could have caused capitalized costs to exceed the cost ceiling, resulting in a non-cash charge against income. The value of oil and gas properties is highly dependent upon the prices of oil and natural gas.

Since January 1, 2011, Penn West has followed the accounting guidelines under IFRS. Under IFRS, the impairment test is performed at a lower level than previously under Canadian GAAP. As a consequence, impairment provisions are more likely to occur going forward under IFRS, as properties will no longer be tested at only the country level and impairment can also be reversed if parameters change in the future.

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 permanent impairment be charged to income. A permanent 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, 2011, 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. 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.

Both Canadian GAAP and IFRS in respect of 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.

We cannot assure you that the dividends and distributions 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 $2.75 billion and a maturity date of June 26, 2015, which is extendible with lender approval. As of March 15, 2012, approximately $1.5 billion was outstanding under our credit facility. In the event that our credit facility is not extended before June 26, 2015, 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 require principal repayments starting in May 2014 and continuing until December 2025. In the event we are unable to repay or refinance these debt obligations 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 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.

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 (which have since improved significantly) but 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 15, 2012, we had approximately $1.3 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.

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 among Penn West and certain lenders and other parties in respect of Penn West's $2.75 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 the 2007 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 the 2008 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 the 2008 Senior Notes (Pounds Sterling), 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 the 2009 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 the 2010 Q1 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 the 2010 Q4 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 the 2011 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) 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 BNY Mellon 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 "**Engineer**" and collectively, the "**Engineers**"), KPMG LLP ("**KPMG**"), our auditors, and Burnet, Duckworth & Palmer LLP, our legal counsel ("**BDP**", and together with the Engineers, the " **Experts**").

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.

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, KPMG or BDP 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, except for John A. Brussa, the Chairman of Penn West, who is a partner of BDP.

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, 2011, 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 of Penn West 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) Hilary Foulkes
Executive Vice President and Chief Operating Officer

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

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

March 15, 2012

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, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, 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, 2011, 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 26, 2012	Canada	$ —	$ 5,843	$ —	$ 5,843
Sproule Associates Limited	February 6, 2012	Canada	$2,136	$ 4,040	$ —	$ 6,176
Sproule Associates Limited	February 6, 2012	USA	$ —	$ 24	$ —	$ 24
Totals			$2,136	$ 9,907	$ —	$ 12,042

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.
Calgary, Alberta, Canada
March 15, 2012

(signed) Sproule Associates Limited
Calgary, Alberta, Canada
March 15, 2012

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 15, 2012 is set forth below (the " **Statement**"). The effective date of the Statement is December 31, 2011 and the preparation date of the Statement is March 15, 2012. 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, 2011 contained in the GLJ Report; and (ii) an evaluation and audit prepared by Sproule with an effective date of December 31, 2011 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 34 percent and to audit approximately 18 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 Reserve 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 and North Dakota. 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 of approximately 2 MMboe, which represents less than one percent of our total proved plus probable reserves, and have a before tax net present value discounted at 10 percent of approximately $24 million, which represents less than one percent of the total value of our proved plus probable reserves.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast 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 (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (MMbbl)	Net (MMbbl)	Gross (MMbbl)	Net (MMbbl)
PROVED				
Developed Producing	204	176	48	44
Developed Non-Producing	6	5	1	1
Undeveloped	78	67	2	2
TOTAL PROVED	288	248	51	47
PROBABLE	113	93	22	19
TOTAL PROVED PLUS PROBABLE	401	342	73	66

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Bcf)	Net (Bcf)	Gross (MMbbl)	Net (MMbbl)
PROVED				
Developed Producing	661	582	23	17
Developed Non-Producing	35	29	1	1
Undeveloped	88	78	4	3
TOTAL PROVED	783	689	28	21
PROBABLE	452	383	12	9
TOTAL PROVED PLUS PROBABLE	1,235	1,073	39	30

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (MMboe)	Net (MMboe)
PROVED		
Developed Producing	385	334
Developed Non-Producing	13	11
Undeveloped	99	86
TOTAL PROVED	498	430
PROBABLE	222	186
TOTAL PROVED PLUS PROBABLE	719	616

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2011
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	13,556	9,464	7,417	6,177	5,337	22.21	3.70
Developed Non-Producing	418	298	232	191	163	21.58	3.60
Undeveloped	3,870	2,242	1,406	916	603	16.39	2.73
TOTAL PROVED	17,844	12,004	9,055	7,283	6,103	21.04	3.51
PROBABLE	9,218	4,785	2,988	2,070	1,530	16.10	2.68
TOTAL PROVED PLUS PROBABLE	27,063	16,790	12,042	9,354	7,633	19.55	3.26

Note:

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

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2011
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	11,734	8,441	6,753	5,710	4,993
Developed Non-Producing	314	226	178	149	129
Undeveloped	2,909	1,638	980	595	349
TOTAL PROVED	14,957	10,305	7,912	6,454	5,471
PROBABLE	6,909	3,566	2,205	1,509	1,100
TOTAL PROVED PLUS PROBABLE	21,865	13,871	10,117	7,963	6,571

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2011
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	41,954	5,981	14,682	2,459	987	17,844	2,888	14,957
Proved Plus Probable Reserves	61,707	9,193	20,802	3,522	1,128	27,063	5,197	21,865

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2011
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]	7,283	21.93	3.66
	Heavy Oil[1]	1,147	23.07	3.85
	Natural Gas[2]	600	13.79	2.30
	Non-Conventional Oil and Gas Activities	24	3.40	0.57
	TOTAL	9,055	21.04	3.51
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	9,592	20.45	3.41
	Heavy Oil[1]	1,634	23.27	3.88
	Natural Gas[2]	773	13.19	2.20
	Non-Conventional Oil and Gas Activities	43	2.07	0.35
	TOTAL	12,042	19.55	3.26

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.

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.

(f) **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.

(g) **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, 2011
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										
2012	97.53	97.42	81.83	90.11	3.32	56.15	74.31	105.66	2.0	1.0
2013	97.45	97.38	81.01	90.06	3.95	56.45	74.34	104.16	2.0	1.0
2014	96.00	95.95	79.79	88.23	4.36	55.80	73.27	101.11	2.0	1.0
2015	98.71	98.63	82.06	90.71	5.29	57.69	75.26	103.97	2.0	1.0
2016	99.68	99.59	82.88	91.61	5.58	58.20	75.98	105.00	2.0	1.0
2017	100.68	100.57	83.72	92.52	5.87	58.72	76.71	106.05	2.0	1.0
2018	102.37	102.26	85.13	94.08	6.05	59.67	77.99	107.84	2.0	1.0
2019	104.41	104.32	86.84	95.97	6.17	60.83	79.57	110.01	2.0	1.0
2020	106.50	106.42	88.59	97.90	6.30	62.01	81.16	112.22	2.0	1.0
Thereafter	2%	2%	2%	2%	2%	2%	2%	2%	2%	—

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, 2011 were $3.78/Mcf for natural gas, $86.71/bbl for light and medium crude oil, $69.07/bbl for heavy oil and $64.92/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$)	Proved Plus Probable Reserves (MM$)
2012	972	1,382
2013	736	1,001
2014	424	631
2015	81	142
2016	53	80
2017 and subsequent	193	286
Total: Undiscounted for all years	2,459	3,522

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, 2011, 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, 2010	259	94	353	54	14	68	865	370	1,235
Extensions	18	11	29	1	1	2	41	109	150
Improved Recovery[1]	32	11	43	2	7	9	43	15	59
Technical Revisions	8	(3)	5	1	—	1	40	(29)	11
Discoveries	—	—	—	—	—	—	—	—	—
Acquisitions	5	1	6	—	—	—	13	4	16
Dispositions	(6)	(3)	(9)	—	—	(1)	(22)	(7)	(30)
Economic Factors	—	1	1	—	—	1	(68)	(10)	(79)
Production	(27)	—	(27)	(7)	—	(7)	(128)	—	(128)
December 31, 2011	288	113	401	51	22	73	783	452	1,235

Note:

(1) Improved recovery includes the following infill drilling:

Infill Drilling	32	10	42	1	2	3	41	15	57

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, 2010	24	9	33	481	179	661
Extensions	3	1	4	28	32	60
Improved Recovery[1]	3	1	4	45	21	66
Technical Revisions	3	1	4	19	(8)	12
Discoveries	—	—	—	—	—	—
Acquisitions	1	—	1	8	2	10
Dispositions	—	—	(1)	(11)	(4)	(15)
Economic Factors	(2)	(1)	(3)	(13)	(1)	(15)
Production	(4)	—	(4)	(59)	—	(59)
December 31, 2011	28	12	39	498	222	719

Notes:

(1) Improved recovery includes the following infill drilling:

Infill Drilling	2	—	2	41	15	57

(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 two-thirds 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	9	37	5	6	44	62	—	1
2009	17	46	—	2	7	61	—	1
2010	16	51	—	1	28	83	1	2
2011	39	78	2	2	60	88	3	4

GLJ and Sproule have assigned 99 MMboe of proved undeveloped reserves in the Engineering Reports under forecast prices and costs, together with $2,081 million of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Engineering Reports accounts for $1,538 million, or 74 percent, of the total forecast undiscounted capital expenditures for proved undeveloped reserves. These figures increase to $2,019 million, or 97 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	11	32	14	13	57	79	1	2
2009	26	51	—	2	7	60	—	2
2010	11	36	1	1	52	112	—	2
2011	22	51	8	9	125	207	2	4

GLJ and Sproule have assigned 98 MMboe of probable undeveloped reserves in the Engineering Reports under forecast prices and costs, together with $1,006 million of associated undiscounted future capital expenditures. Probable undeveloped capital spending in the first two forecast years of the Engineering Reports accounts for $654 million, or 65 percent, of the total forecast undiscounted future capital expenditures for probable undeveloped reserves. These figures increase to $924 million, or 92 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, 2011, we expect to incur future A&R Costs in respect of approximately 22,127 net well bores and 2,404 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, 2011	7,004	513
Anticipated to be paid in 2012	75	68
Anticipated to be paid in 2013	77	63
Anticipated to be paid in 2014	78	59

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 $5,876 million, and escalated at two percent and discounted at 10 percent, these A&R Costs were $473 million.

OTHER OIL AND GAS INFORMATION

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

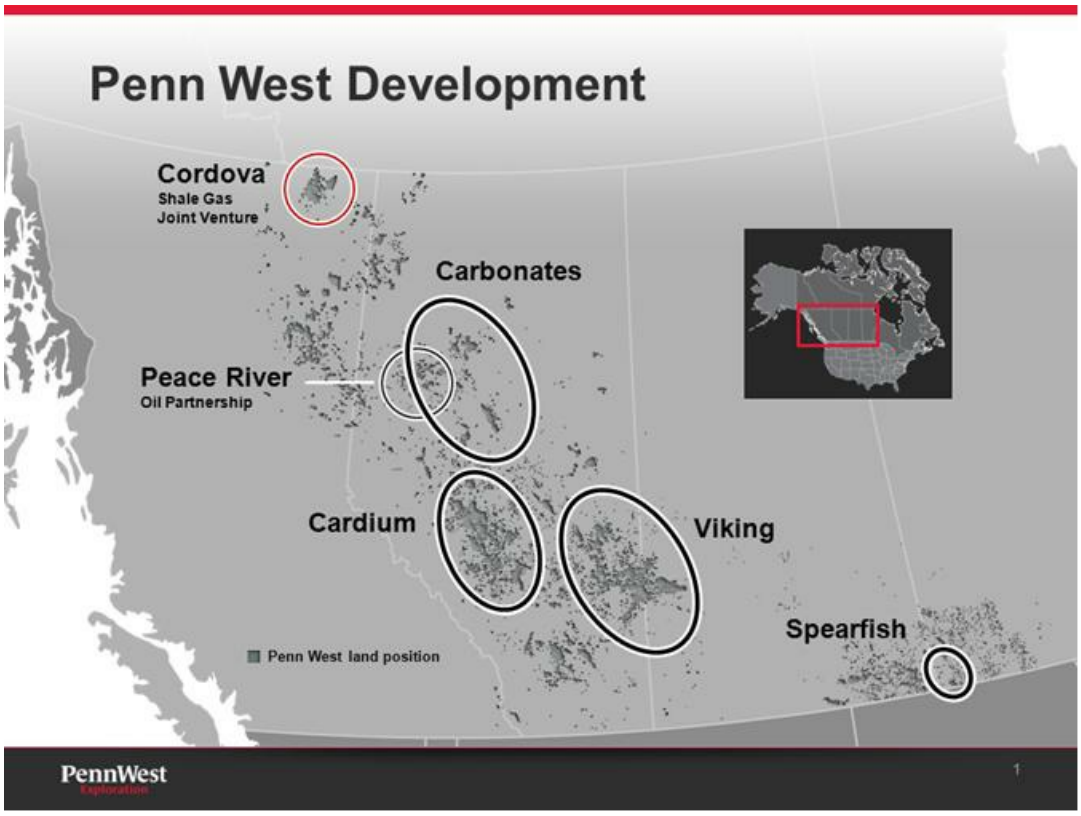
Introduction

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, 2011 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 and North Dakota.

Major Operating Regions

Our production and reserves are attributed to approximately 300 producing properties. No single property accounts for more than 10 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, 2011.



The following is a description of our principal oil and natural gas properties and related operations and activities as at December 31, 2011. Information in respect of gross and net acres and well counts are as of December 31, 2011 and information in respect of production is for the year ended December 31, 2011, except where indicated otherwise. Due to the fact that we have been active at acquiring additional interests in our principal properties, the working interest share in gross and net acres and wells at December 31, 2011 may not directly correspond to our reported production for the year, which only includes production from the date of acquisition. **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.**

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. In 2011, Penn West added key strategic infrastructure and significantly increased its land position in the area. The 2011 capital program in the Carbonates was focused on the development in the Slave Point and Swan Hills areas with over 40 net wells drilled. As at December 31, 2011, Penn West had a developed and undeveloped land position of approximately 380,000 net acres relating to the Carbonates resource play. In 2012, Penn West expects overall capital expenditures to total approximately $300 million to $350 million for the play.

Cardium Resource Play

The Cardium resource play is located in west central Alberta and extends between Calgary and Grande Prairie, Alberta. At December 31, 2011, Penn West had approximately 665,000 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 properties. In 2011, Penn West's capital program was concentrated on moving to full-scale development in portions of this play and the drilling of approximately 100 net wells. In 2012, Penn West has allocated approximately $225 million to $275 million of capital to the Cardium.

Waskada Resource Play

Waskada is a tight, light-oil play located in the area of southwestern Manitoba near the Canada/U.S. border. In 2011, we focused on the assessment and development of the play and drilled approximately 95 net wells and began facility expansion to accommodate increased production levels. Penn West held 75,000 net acres of developed and undeveloped land as at December 31, 2011. In 2012, Penn West anticipates capital spending of approximately $200 million to $250 million at Waskada, including the completion of Penn West's oil battery in the first quarter of 2012.

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, with a high portion of liquids production, in eastern Alberta. Penn West has a significant land position in this play of approximately 750,000 net acres of developed and undeveloped land at December 31, 2011. Penn West concentrated its 2011 capital program on both tight-oil development and exploration drilling in the area with over 90 net wells drilled. In 2012, Penn West plans to spend approximately $125 million to $175 million of capital on the Viking resource play with development on the Saskatchewan side of the play and further appraisal of the oil potential on the Alberta side.

Peace River Assets

The Peace River Assets are a significant bitumen 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 bitumen resources in the area, and under this partnership, Penn West has retained a 55 percent interest in the Peace River Assets, with the CIC Affiliate holding the remaining 45 percent interest.

PROP has a strong land position in this play comprised of approximately 243,000 net acres of developed and undeveloped land at December 31, 2011. In 2011, PROP focused its activities on a significant appraisal well drilling program and completed the first cycle of production at the Seal Main cyclic steam pilot. In 2012, PROP plans to continue its resource assessment and advance its thermal assessment program with plans of approximately $135 million of capital for the first six months of 2012. PROP's budget year is from July 1 to June 30 and is currently in the budgeting process to establish capital requirements for the last six months of 2012.

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 located in the most northern portion of northeastern British Columbia in the Wildboy area. This play is a legacy Penn West exploration and development property targeting natural gas production that includes significant production infrastructure in place and all-weather access roads. This play was initially developed by Penn West in the late 1990's using vertical drilling technology. The play area includes a natural gas plant and sales pipeline that connects to the TransCanada pipeline system in Alberta and is now 50 percent owned and operated by Penn West under the Cordova JV.

Penn West's focus for growth in this area is the shale gas play in the Cordova Embayment, located east of the Horn River development. In September 2010, the Cordova JV was formed to accelerate the appraisal and development of these assets. The Cordova JV had a total of approximately 260,000 net acres of developed and undeveloped land in the area at December 31, 2011. The capital program in 2011 was focused on resource appraisal and the drilling and completion of the first multi-well pad in the area. In 2012, under the Cordova JV, Penn West expects to continue the evaluation of the play area with further resource appraisal and total capital expenditures of approximately $320 million ($80 million net to Penn West).

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 recent advancements in drilling, completions and other technologies will enable Penn West to pursue various enhanced recovery techniques aimed at increasing oil recovery rates in several of its large plays. Penn West has completed successful steam injection, waterflood and CO2 miscible flooding pilot projects in several of its oil fields. Penn West is also involved in several commercial CO2 EOR projects including the Joffre area in Alberta and the Weyburn and Midale areas in Saskatchewan.

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 material 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, 2011.

	Producing				Non-Producing		Total	
	Oil		Gas					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	9,028	5,532	6,097	3,784	7,824	4,828	22,949	14,144
British Columbia	270	110	845	328	362	135	1,477	573
Saskatchewan	7,710	5,368	562	448	1,980	909	10,252	6,725
Manitoba	793	403	—	—	229	117	1,022	520
Northwest Territories	4	—	9	1	34	5	47	6
Wyoming	—	—	204	71	169	71	373	142
Montana	2	—	—	—	—	—	2	—
North Dakota	30	16	—	—	2	1	32	17
Total	17,837	11,429	7,717	4,632	10,600	6,066	36,154	22,127

Properties with no Attributed Reserves

The following table sets out the unproved properties in which we had an interest as at December 31, 2011.

	Unproved Properties (thousands of acres)	
	Gross	Net
Alberta	1,740	1,335
British Columbia	636	308
Saskatchewan	287	228
Manitoba	209	203
Northwest Territories	85	18
North Dakota	8	5
Wyoming	15	8
Total	2,980	2,105

We currently have no material work commitments on these lands. The primary lease or extension term on approximately 185,000 net acres of unproved property is scheduled to expire by December 31, 2012. 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 until at least the 2014 taxation year. 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, 2011, irrespective of whether such costs were capitalized or charged to expense when incurred.

	2011 MM$
Property Acquisition Costs[1]	
Proved Properties	(266)
Unproved Properties	181
Exploration Costs[1]	330
Development Costs[1]	1,417
Corporate Costs	25
Joint venture, carried capital	(107)
Total Capital Expenditures	1,580
Corporate Acquisitions	286
Total Expenditures	1,866

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, 2011.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	2	1	455	352
Natural Gas	15	8	38	28
Service	—	—	69	27
Stratigraphic test	1	1	19	9
Dry	—	—	—	—
Total	18	10	581	416

We currently estimate that our capital expenditures in 2012 will be between $1.3 billion and $1.4 billion, after the effect of net asset dispositions completed to March 15, 2012, in order to execute our current 2012 capital programs. 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, 2012 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	64,840	54,681	16,269	14,260	275,621	242,510	9,558	7,268	136,604	116,627
Proved Developed Non- Producing	1,684	1,432	63	52	7,678	6,687	208	175	3,234	2,774
Proved Undeveloped	12,437	11,445	409	378	15,896	14,258	950	872	16,446	15,071
Total Proved	78,961	67,558	16,741	14,690	299,195	263,455	10,716	8,316	156,284	134,472
Total Probable	7,724	6,856	1,058	867	52,816	45,539	907	792	18,492	16,104
Total Proved Plus Probable	86,686	74,413	17,799	15,557	352,009	308,994	11,623	9,107	174,776	150,576

No one field (being a defined geographical area consisting of one or more pools) accounts for more than five 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 2011				Year Ended December 31, 2011
	March 31	June 30	September 30	December 31	
Share of Average Gross Daily Production					
Light and Medium Crude Oil (bbl/d)	77,892	70,997	73,640	78,727	75,312
Heavy Oil (bbl/d)	17,115	18,452	18,105	17,886	17,892
Gas (MMcf/d)	371	343	360	364	359
NGLs (bbl/d)	9,342	9,549	9,647	11,458	10,004
Combined (boe/d)	166,135	156,107	161,323	168,801	163,094
Average Net Production Prices Received					
Light and Medium Crude Oil ($/bbl)	82.11	98.10	84.39	91.92	89.01
Heavy Oil ($/bbl)	62.79	72.81	63.38	76.88	69.07
Gas ($/Mcf)	3.79	4.06	3.81	3.47	3.78
NGLs ($/bbl)	60.21	66.00	65.74	67.08	64.92
Combined ($/boe)	56.82	66.18	58.05	63.05	60.99
Royalties Paid					
Light and Medium Crude Oil ($/bbl)	14.94	18.65	15.86	16.66	16.49
Heavy Oil ($/bbl)	8.99	10.61	9.54	10.82	10.01
Gas ($/Mcf)	0.48	0.55	0.56	0.59	0.54
NGLs ($/bbl)	18.67	17.64	22.14	18.88	19.33
Combined ($/boe)	10.04	12.01	10.87	11.47	11.09

	Quarter Ended 2011				Year Ended December 31, 2011
	March 31	June 30	September 30	December 31	
Production Costs[1][2]					
Light and Medium Crude Oil ($/bbl)	19.43	24.02	21.83	21.36	21.61
Heavy Oil ($/bbl)	17.66	17.61	17.42	17.42	17.53
Gas ($/Mcf)	1.85	2.11	2.04	2.11	2.03
NGLs ($/bbl)	15.18	18.72	17.02	16.60	16.88
Combined ($/boe)	15.92	18.79	17.49	17.48	17.40
Transportation					
Light and Medium Crude Oil ($/bbl)	—	—	—	—	—
Heavy Oil ($/bbl)	0.11	0.09	0.07	0.07	0.08
Gas ($/Mcf)	0.23	0.21	0.22	0.22	0.22
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	0.51	0.48	0.49	0.48	0.49
Loss on Risk Management Contracts					
Light and Medium Crude Oil ($/bbl)	1.68	5.06	0.82	1.81	2.30
Heavy Oil ($/bbl)	—	—	—	—	—
Gas ($/Mcf)	—	—	—	—	—
NGLs ($/bbl)	—	—	—	—	—
Combined ($/boe)	0.79	2.30	0.37	0.84	1.06
Netback Received[3]					
Light and Medium Crude Oil ($/bbl)	46.06	50.37	45.88	52.09	48.61
Heavy Oil ($/bbl)	36.03	44.50	36.35	48.57	41.45
Gas ($/Mcf)	1.23	1.19	0.99	0.55	0.99
NGLs ($/bbl)	26.36	29.64	26.58	31.60	28.71
Combined ($/boe)	29.56	32.60	28.83	32.78	30.95

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, 2011, Penn West produced 60 MMboe, comprised of 27 MMbbl of light and medium oil, 7 MMbbl of heavy oil, 131 MMcf of natural gas and 4 MMbbl of natural gas liquids.

Marketing Arrangements

Our marketing approach incorporates the following primary objectives:

- Ensure security of market and avoid production shut-ins due to marketing constraints by dealing with end-users or regionally strategic counterparties wherever possible.
- Ensure competitive pricing by managing pricing exposures through a portfolio of various terms and geographic basis.
- Ensure optimization of netbacks through careful management of transportation obligations, facility utilization levels, blending opportunities and emulsion handling.

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

Oil and Liquids Marketing

Of our liquids production, approximately 73 percent is light and medium oil, 17 percent is conventional heavy oil and 10 percent is NGLs. In regard specifically to crude oil, our average quality is 32.3 degrees API, which is comprised of an average quality for our light and medium oil of 36.0 degrees API and an average quality for our conventional heavy oil of 13.0 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, trucking and proprietary handling of emulsion. 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:

	2011		2010		2009	
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	79.76	62.79	72.72	64.31	44.50	36.92
June 30	94.29	72.81	67.70	57.03	58.11	56.71
September 30	82.23	63.38	65.68	58.81	64.15	58.72
December 31	88.76	76.88	71.05	61.87	69.49	62.97

Natural Gas Marketing

In 2011, we received an average price from the sale of natural gas, before adjustments for hedging activities, of $3.78/Mcf compared to $4.20/Mcf realized in 2010. Approximately 94 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 14 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. For information in relation to marketing arrangements, see “Other Oil and Gas Information – Marketing Arrangements”.

As at December 31, 2011, we were not bound by any agreement (including a transportation agreement), directly or through an aggregator, under which we may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or natural gas, except for agreements disclosed by us in Note 12 to our audited consolidated financial statements as at and for the year ended December 31, 2011, 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, 2011

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, 2011 and 2010. The date of this MD&A is March 15, 2012. All dollar amounts contained in this MD&A are expressed in millions of Canadian dollars unless noted otherwise.

For additional information, including Penn West's 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. All 2009 balances remain in accordance with previous GAAP.

Please refer to our disclaimer 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.

Non-GAAP 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 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 GAAP. Netback is the per unit of production amount of revenue less royalties, operating costs, transportation and realized risk management used in capital allocation decisions and to economically rank projects. Return on equity is the rate of return calculated by comparing net income to shareholders' equity. Return on capital is calculated using net income excluding financing charges compared to shareholders' equity and long-term debt and is used to assess how well Penn West utilizes the capital invested into the company.

Calculation of Funds Flow

	Year ended December 31	
(millions, except per share amounts)	**2011**	2010
Cash flow from operating activities	**$ 1,407**	$ 1,217
Increase (decrease) in non-cash working capital	**49**	(85)
Decommissioning expenditures	**81**	53
Funds flow	**$ 1,537**	$ 1,185
Basic per share	**$ 3.29**	$ 2.68
Diluted per share	**$ 3.29**	$ 2.65

Annual Financial Summary

(millions, except per share amounts)	Year ended December 31		
	2011	2010 (1)	2009 (1)
Gross revenues (2)	**$ 3,604**	$ 3,034	$ 3,203
Funds flow	**1,537**	1,185	1,493
Basic per share	**3.29**	2.68	3.62
Diluted per share	**3.29**	2.65	3.60
Net income (loss)	**638**	1,110	(144)
Basic per share	**1.37**	2.51	(0.35)
Diluted per share	**1.36**	2.48	(0.35)
Capital expenditures, net (3)	**1,580**	(119)	319
Long-term debt at year-end	**3,219**	2,496	3,219
Convertible debentures	**—**	255	273
Dividends/ distributions paid (4)	**420**	708	910
Total assets	**$15,584**	$14,543	$13,876

(1) Comparative 2010 figures are presented under IFRS. Comparative 2009 figures are presented under previous GAAP.
(2) Gross revenues include realized gains and losses on commodity contracts.
(3) Excludes business combinations.
(4) Includes dividends paid and reinvested in shares under the dividend reinvestment plan.

2011 Highlights

- Funds flow for 2011 increased 30 percent to $1,537 million compared to $1,185 million in 2010. The increase was due to higher revenues as a result of higher liquids production and stronger crude oil prices.
- Net income was $638 million in 2011 compared to $1,110 million in 2010. Prior year figures include a $572 million after-tax gain on the formation of the Peace River Oil Partnership and a $368 million gain on the formation of the Cordova Joint Venture.
- Annual 2011 production averaged 163,094 boe per day, in line with our previous annual guidance of 162,000 to 164,000 boe per day.
- Capital expenditures totalled $1,580 million net of joint venture carried capital and proceeds on net asset dispositions of $266 million. To date in 2012, Penn West has closed net dispositions of approximately $340 million.
- Netbacks were $30.95 per boe compared to $25.07 per boe in 2010, due primarily to higher liquid prices.

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

Three months ended	**Dec. 31 2011**	Sep. 30 2011	June 30 2011	Mar. 31 2011	Dec. 31 2010	Sep. 30 2010	June 30 2010	Mar. 31 2010
Gross revenues (1)	**$ 979**	$ 861	$ 920	$ 844	$ 782	$ 728	$ 718	$ 806
Funds flow	**437**	348	396	356	305	267	269	344
Basic per share	**0.93**	0.74	0.85	0.77	0.67	0.59	0.62	0.81
Diluted per share	**0.93**	0.74	0.85	0.77	0.66	0.58	0.61	0.81
Net income (loss)	**(62)**	138	271	291	(37)	304	745	98
Basic per share	**(0.13)**	0.29	0.58	0.63	(0.08)	0.67	1.72	0.23
Diluted per share	**(0.13)**	0.29	0.58	0.63	(0.08)	0.66	1.69	0.23
Dividends declared	**127**	127	127	125	123	177	196	190
Per share	**$ 0.27**	$ 0.27	$ 0.27	$ 0.27	$ 0.27	$ 0.39	$ 0.45	$ 0.45
Production								
Liquids (bbls/d) (2)	**108,071**	101,392	98,998	104,349	105,296	98,380	95,777	96,317
Natural gas (mmcf/d)	**364**	360	343	371	365	394	408	410
Total (boe/d)	**168,801**	161,323	156,107	166,135	166,148	164,087	163,700	164,587

(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 program on appraisal activities across our light-oil plays in the Cardium, Carbonates, Spearfish and Viking where we have significant legacy production, land and infrastructure positions. In 2011, we concentrated on moving these projects from the resource appraisal phase into full-scale development. In 2012, our focus remains on these key light-oil projects with a further shift toward full-scale development across portions of these plays. The application of horizontal multi-stage drilling technologies continues to be a key component of our success along with continuous operations and the use of pad drilling techniques to drive improved capital efficiencies. In 2012, we plan to continue the appraisal activities within the Peace River Oil Partnership and the Cordova Joint Venture with our partners. Further appraisal of our extended portfolio of light-oil and liquids-rich gas plays will continue at a less aggressive pace than in 2010 and 2011. Our unique ownership of light-oil and liquids-rich resources combined with successful resource appraisal over the past several years and our increasing expertise in new drilling and completions technologies provides us significant opportunities for large-scale oil development in a politically stable environment.

Business Environment

Crude oil markets were volatile in 2011 due to a number of factors. Supply concerns resulting from social unrest in the Middle East and North Africa led to a rise in crude oil prices in the first half of the year. The loss of crude oil exports from Libya led to prices peaking early in the second quarter. In the second half of 2011, exports resumed from Libya at a faster than expected rate resulting in lower crude oil prices. European sovereign debt concerns reduced confidence in the outlook for global economic growth which also exerted downward pressure on crude oil prices. Since the latter part of 2011, crude oil prices have recovered to above US$100 WTI as the market fundamentals re-balanced. As we enter 2012, the European Union continues to address its debt issues; however, it is not clear when these issues will be resolved. Analysts are currently forecasting a modest level of global GDP growth in 2012 which is expected to result in incremental demand for crude oil. Crude oil prices have also strengthened to date in 2012 due to tightening unutilized OPEC capacity and geo-political tensions in certain parts of the world, including Iran, where economic sanctions on Iran's oil trade could result in future oil supply volatility.

Historically, WTI has traded at a premium to Brent however in 2011 WTI traded at a significant discount to Brent and other world benchmark crudes. This spread peaked at US$27 per barrel during 2011, but has recently settled at approximately US$20 per barrel. A number of factors contributed to this spread, notably: WTI is priced at Cushing, Oklahoma and thus is a "land-locked" crude that does not fully participate in price increases in comparison to crude oil that has ocean access; the loss of Libyan exports earlier in 2011 caused European buyers to place a premium on other streams such as Brent; inventory levels at Cushing rose to high levels; and, North Sea production problems further contributed to premium Brent pricing. In order for this price differential to fully reverse, additional transportation between Cushing and the Gulf Coast is believed to be required. Currently, both TransCanada and Enbridge have pipeline projects that, if approved and completed, will enable Canadian crudes to be transported to the Gulf Coast where they will have greater access to world prices. In January 2012, the US government rejected TransCanada's permit for the Keystone XL pipeline project, however, TransCanada has the option to reapply for a permit in the future. In February 2012, TransCanada announced plans to begin building the south leg of the Keystone XL pipeline which will connect Cushing, Oklahoma to the Texas Gulf Coast. We have made commitments that will allow us to participate in one of these development projects and we continue to monitor the progress and assess the merits of other projects.

In February 2012, differentials for Canadian oil to WTI widened compared to historical levels. Lower refinery runs due to earlier than normal turnarounds and the need to work down high gasoline inventory levels have recently softened demand for Canadian crudes. We expect these differentials will normalize as refineries come back on-line and as inventory levels re-balance.

Despite 2011 increases in demand in the industrial and power generation sectors, North America natural gas markets continue to be over-supplied. The drilling activities in liquids-rich shale gas plays remain robust resulting in increasing natural gas production despite weak natural gas pricing. The combination of increased supply and a mild 2011 winter have led to lower heating demand and record levels of inventory. Over the next several years, North American access to international gas markets through the development of LNG infrastructure appears to be an important part of rebalancing North American supply and demand.

Crude Oil

In 2011, WTI crude oil prices averaged US$95.14 per barrel compared to US$79.55 per barrel in 2010. Over the past year, Canadian producers experienced delays delivering their production to market due to increasing supply and a number of pipeline interruptions. Some transportation issues continue in 2012 due to increased repair and maintenance programs and reduced capacity on some lines which have encountered operational issues. As an alternative, the use of rail transportation has increased to address congestion. In the future, the benefits of increased reliability due to recent maintenance programs and various expansion projects are expected to reduce disruptions.

Penn West's average crude oil price for 2011 before the impact of the realized portion of risk management was $83.22 per barrel. Currently Penn West has 60,000 barrels per day of its 2012 crude oil production hedged between US$85.53 and US$101.16 per barrel and 35,000 barrels per day of its forecast 2013 production hedged between US$93.57 and US$107.91 per barrel.

Natural Gas

In 2011, the AECO Monthly Index averaged $3.67 per mcf compared to $4.12 per mcf in 2010. The continued drilling activity in liquids-rich shale gas plays in the U.S. is reducing the demand for Canadian gas exports. Currently, Western Canadian gas producers face two specific challenges compared to their U.S. competitors. Firstly, certain Western Canadian gas streams are drier than many of the U.S. shale gas plays thus price realizations are lower due to lower liquids content, and secondly, the longer distance to end markets means that Western Canadian gas producers incur higher transportation costs. Current forecasts, at current drilling activity levels, project natural gas liquids production to eventually over supply North American markets resulting in downward pressure on prices, reducing the value discrepancy between wet and dry gas plays. Many analysts believe the solution for Western Canadian gas is to build the infrastructure capable of providing access to higher netback markets outside of North America, such as Asia.

Penn West's corporate average natural gas price for 2011 before the impact of the realized portion of risk management was $3.78 per mcf. Penn West currently has 50,000 mcf per day of natural gas production hedged for 2012 at an average price of $4.30 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, balance sheet stewardship, financial stewardship and the overall goal of creating competitive return on investment for our shareholders.

Finding and Development costs

	Year ended December 31			
	2011	2010	2009	3-Year average
Adjusted F&D costs including future development costs ("FDC") (1)				
F&D costs per boe—proved plus probable	**$ 22.64**	$ 21.97	$ 15.18	$ 20.97
F&D costs per boe—proved	**$ 29.71**	$ 23.56	$ 15.63	$ 24.70
Excluding FDC (2)				
F&D costs per boe—proved plus probable	**$ 15.07**	$ 18.90	$ 13.75	$ 15.81
F&D costs per boe—proved	**$ 23.55**	$ 21.50	$ 16.10	$ 21.11
Including FDC (3)				
F&D costs per boe—proved plus probable	**$ 26.79**	$ 26.73	$ 16.12	$ 24.51
F&D costs per boe—proved	**$ 37.05**	$ 28.01	$ 16.19	$ 29.17

(1) The calculation of adjusted F&D includes the change in FDC, excludes the effect of economic revisions related to downward revisions of natural gas prices and excludes land acquisition costs.
(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.

In 2011, we increased our capital program as we completed our transition to an E&P corporation and continued to focus on our portfolio of light-oil plays. Our successful drilling program in 2011 resulted in an increase in liquids reserves which led to an increase in total reserves. On a proved basis, our reserves are weighted 74 percent to crude oil and liquids (2010 – 70 percent). On a proved plus probable basis our reserves are weighted 71 percent to crude oil and liquids (2010 – 69 percent) and 29 percent to natural gas (2010 – 31 percent).

Capital expenditures for 2011 are net of $107 million related to joint venture carried capital (2010 – $17 million). We use Adjusted F&D to assess the economic viability and the stage of development of our resource plays. F&D costs are calculated in accordance with National Instrument 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

In 2011, we moved toward full-scale development on many of our light-oil plays. During the second quarter of 2011, severe flooding in Saskatchewan and Manitoba and wild fires in Alberta caused temporary operating interruptions which we overcame during the third quarter. We ended 2011 with significant operational momentum and have continued to build on this early in 2012.

Shareholder Value Measures

	Year ended December 31		
	2011	2010 (1)	2009 (1)
Funds flow per share	**$ 3.29**	$ 2.68	$ 3.62
Dividends/ distributions paid per share	**$ 0.90**	$ 1.62	$ 2.23
Ratio of year-end total long-term debt to annual funds flow	**2.1:1**	2.1:1	2.2:1

(1) Comparative 2010 figures are presented under IFRS. Comparative 2009 figures are presented under previous GAAP.

In April 2011, we began paying a quarterly dividend of $0.27 per share as a corporation. Our last monthly distribution payment of $0.09 per unit as a trust was declared in December 2010 and paid in January 2011. Currently, our business strategy is to provide shareholder return through a combination of oil-oriented growth and yield.

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		
	2011	2010 (1)	2009 (1)
Return on capital (2)	**7%**	11%	—
Return on equity (3)	**7%**	13%	(2)%
Total assets (millions)	**$ 15,584**	$ 14,543	$ 13,876

(1) Comparative 2010 figures are presented under IFRS. Comparative 2009 figures are presented under previous GAAP.
(2) Net income before financing charges divided by average shareholders' equity and average total debt.
(3) Net income divided by average shareholders' equity.

The return on capital and return on equity ratios in 2011 decreased in comparison to 2010 as a result of lower net income mainly due to an increase in unrealized risk management losses and a decline in gains on dispositions, both non-cash items. In 2010, we recorded significant gains on dispositions as a result of forming the Peace River Oil Partnership and the Cordova Joint Venture.

RESULTS OF OPERATIONS

Production

	Year ended December 31		
Daily production	**2011**	2010	% change
Light oil and NGL (bbls/d)	**85,316**	80,706	6
Heavy oil (bbls/d)	**17,892**	18,260	(2)
Natural gas (mmcf/d)	**359**	394	(9)
Total production (boe/d)	**163,094**	164,633	(1)

In 2011, production was disrupted in the second quarter and into the third quarter as a result of extreme flooding in southern Saskatchewan and Manitoba, wild fires in the Slave Lake region in northern Alberta and third party facility outages. As we moved through the third quarter of 2011, activities were concentrated on restoring production and resuming full operations. In the fourth quarter of 2011, we reached full operating capacity and continued to build on a successful capital program. To date in 2012, we have closed property dispositions for proceeds of approximately $340 million.

When economic to do so, we strive to maintain a strategic 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 in the medium term and our significant inventory of light-oil locations, we plan to continue allocating substantially all of our capital investments to oil projects.

Average Sales Prices

	Year ended December 31		
	2011	2010	% change
Light oil and liquids (per bbl)	**$ 86.19**	$ 69.29	24
Risk management loss (per bbl) (1)	**(2.03)**	(2.72)	(25)
Light oil and liquids net (per bbl)	**84.16**	66.57	26
Heavy oil (per bbl)	**69.07**	60.55	14
Natural gas (per mcf)	**3.78**	4.20	(10)
Risk management gain (per mcf) (1)	**—**	0.42	(100)
Natural gas net (per mcf)	**3.78**	4.62	(18)
Weighted average (per boe)	**60.99**	50.74	20
Risk management loss (per boe) (1)	**(1.06)**	(0.34)	100
Weighted average net (per boe)	**$ 59.93**	$ 50.40	19

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

Netbacks

	Year ended December 31		
	2011	2010	% change
Light oil and NGL [1]			
Production (bbls/day)	**85,316**	80,706	6
Operating netback (per bbl):			
Sales price	**$ 86.19**	$ 69.29	24
Risk management loss [2]	**(2.03)**	(2.72)	(25)
Royalties	**(16.83)**	(13.73)	23
Operating costs	**(21.05)**	(19.83)	6
Netback	**$ 46.28**	$ 33.01	40
Heavy oil			
Production (bbls/day)	**17,892**	18,260	(2)
Operating netback (per bbl):			
Sales price	**$ 69.07**	$ 60.55	14
Royalties	**(10.01)**	(8.73)	15
Operating costs	**(17.53)**	(17.14)	2
Transportation	**(0.08)**	(0.09)	(11)
Netback	**$ 41.45**	$ 34.59	20
Total liquids			
Production (bbls/day)	**103,208**	98,966	4
Operating netback (per bbl):			
Sales price	**$ 83.22**	$ 67.68	23
Risk management loss [2]	**(1.68)**	(2.22)	(24)
Royalties	**(15.64)**	(12.81)	22
Operating costs	**(20.44)**	(19.33)	6
Transportation	**(0.01)**	(0.02)	(50)
Netback	**$ 45.45**	$ 33.30	36
Natural gas			
Production (mmcf/day)	**359**	394	(9)
Operating netback (per mcf):			
Sales price	**$ 3.78**	$ 4.20	(10)
Risk management gain [2]	**—**	0.42	(100)
Royalties	**(0.54)**	(0.58)	(7)
Operating costs	**(2.03)**	(1.71)	19
Transportation	**(0.22)**	(0.22)	—
Netback	**$ 0.99**	$ 2.11	(53)
Combined totals			
Production (boe/day)	**163,094**	164,633	(1)
Operating netback (per boe):			
Sales price	**$ 60.99**	$ 50.74	20
Risk management loss [2]	**(1.06)**	(0.34)	100
Royalties	**(11.09)**	(9.07)	22
Operating costs	**(17.40)**	(15.71)	11
Transportation	**(0.49)**	(0.55)	(11)
Netback	**$ 30.95**	$ 25.07	23

(1) Excluded from the netback calculation is $37 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) 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 2011	2010	2009
Light oil and NGL	**$ 2,657**	$ 1,965	$ 1,920
Heavy oil	**452**	405	509
Natural gas	**495**	664	774
Gross revenues [1]	**$ 3,604**	$ 3,034	$ 3,203

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

Our successful drilling program has resulted in additional light-oil production and an increase in light-oil revenue. Crude oil prices increased in 2011 from 2010 which led to increases in both light and heavy-oil revenues. 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.

The decrease in revenue for 2010 from 2009 was mainly the result of lower realized risk management gains and the impact of net property dispositions which reduced production of heavy oil and natural gas. Light-oil and NGL production increased, notwithstanding the January 2010 asset swap, as we focused our 2010 capital program on light-oil resource plays.

Reconciliation of Increase in Production Revenues

(millions)	
Gross revenues—January 1—December 31, 2010	$ 3,034
Increase in light oil and NGL production	112
Increase in light oil and NGL prices (including realized risk management)	580
Decrease in heavy oil production	(8)
Increase in heavy oil prices	55
Decrease in natural gas production	(58)
Decrease in natural gas prices	(111)
Gross revenues—January 1—December 31, 2011	$ 3,604

Royalties

	Year ended December 31 2011	2010	2009
Royalties (millions)	**$ 661**	$ 545	$ 495
Average royalty rate [1]	**18%**	18%	17%
$/boe	**$11.09**	$9.07	$7.66

(1) Excludes effects of risk management activities.

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

Royalty rates were lower in 2009 due to the effect of the new Alberta royalty programs that became effective for part of 2009. The royalties per boe amount was lower as a result of lower royalty payments due to lower commodity prices.

Expenses

(millions)	Year ended December 31 2011	2010	2009
Operating	**$ 1,036**	$ 944	$ 966
Transportation	**29**	33	34
Financing	**190**	174	161
Share-based compensation	**$ 84**	$ 159	$ 52

(per boe)	Year ended December 31 2011	2010	2009
Operating	**$ 17.40**	$ 15.71	$ 14.93
Transportation	**0.49**	0.55	0.52
Financing	**3.20**	2.89	2.49
Share-based compensation	**$ 1.41**	$ 2.65	$ 0.81

Operating

In 2011, 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 the second half of 2011. These events also contributed to lower average production volumes which led to an increase in operating costs on a per boe basis. Operating costs for 2011 include a realized gain on electricity contracts of $11 million (2010 – $14 million loss and 2009 – $16 million loss). For 2011 the average Alberta pool price was $76.21 per MWh. We have contracts in place that fix the price on approximately 75 percent of our Alberta electricity consumption for 2012 at $53.65 per MWh and additionally in 2013 and 2014 we have approximately 50 percent of our Alberta electricity consumption fixed at $55.20 per MWh and $58.50 per MWh, respectively.

In 2010, acquisition and divestiture activity contributed to an increase in the operating costs per boe. In 2009, there was a greater emphasis on production maintenance activities to maintain production volumes as a weaker commodity price environment in the early part of the year led to us focusing on efficient methods of maintaining production in the short-term.

Financing

The Company has an unsecured, revolving syndicated bank facility with an aggregate borrowing limit of $2.75 billion. The facility expires on June 26, 2015 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, 2011, approximately $1.2 billion was drawn under this facility.

As at December 31, 2011, the Company had $2.0 billion (2010 – $1.7 billion) of senior unsecured notes outstanding with a weighted average interest rate, including the effects of interest rate swaps, of approximately 5.9 percent (2010 – 5.7 percent) and a weighted average remaining term of 6.5 years (2010 – 7.2 years), as follows:

	Issue date	Amount (millions)	Term	Average interest rate	Weighted average remaining term
2007 Notes	May 31, 2007	US$475	8 –15 years	5.80%	5.5 years
2008 Notes	May 29, 2008	US$480, CAD$30	8 –12 years	6.25%	6.0 years
UK Notes	July 31, 2008	£57	10 years	6.95% (1)	6.6 years
2009 Notes	May 5, 2009	US$154, £20, €10, CAD$5	5 – 10 years	8.85% (2)	5.0 years
2010 Q1 Notes	March 16, 2010	US$250, CAD$50	5 – 15 years	5.47%	6.8 years
2010 Q4 Notes	December 2, 2010, January 4, 2011	US$170, CAD$60	5 – 15 years	5.00%	9.7 years
2011 Notes	November 30, 2011	US$105, CAD$30	5 – 10 years	4.49%	8.1 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) 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.

In November 2011, we closed a private placement of senior unsecured notes (the “2011 Notes”) with aggregate principal amounts of approximately $135 million. The 2011 Notes had an original weighted average term of approximately 8.1 years and an average fixed interest rate of approximately 4.49 percent. The Company used the proceeds of the issue to repay advances on its syndicated bank facility.

In January 2011, we completed the closing of a private placement of senior unsecured notes, (the “2010 Q4 Notes”), with an aggregate principal amount of approximately US$230 million. The 2010 Q4 Notes had an original weighted average term of 10.8 years and bear a weighted average fixed interest rate of approximately 5.0 percent. The Company used the proceeds of the issue to repay advances on its syndicated bank facility.

Financing charges in 2011 were higher than in 2010 since a higher percentage of our debt capital was held in longer-term, fixed rate, senior unsecured notes. The cost of borrowing under the current bank facility increased compared to the facility in place during 2009 and the first quarter of 2010 due to increased rates in the bank market. While the Company’s senior unsecured notes contain higher interest rates than the syndicated bank facilities held in short-term money market instruments, we believe the long-term and fixed interest rates inherent in the senior notes are favourable for a portion of our debt capital structure.

The interest rates on any non-hedged portion of the Company’s bank debt are subject to fluctuations in short-term money market rates as advances on the bank facility are generally made under short-term instruments. As at December 31, 2011, 19 percent (2010 – none and 2009 – 14 percent) of our long-term debt instruments were exposed to changes in short-term interest rates.

At December 31, 2011, 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.

Realized gains and losses on the interest rate swaps are recorded as financing costs. For 2011 an expense of $12 million (2010 and 2009 – $21 million) was recognized 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”) as described in Note 15 to our audited consolidated financial statements.

Effective January 1, 2011, we implemented the Option Plan and amended our Trust Unit Rights Incentive Plan (“TURIP”) which became the CSRIP. Pursuant to our plan to convert from a trust to a corporation, trust unit right 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. Those trust unit right 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”) issued under the CSRIP for each trust unit right. After January 1, 2011, all grants are under the Option Plan.

Trust unit rights issued under the former TURIP received liability treatment for accounting purposes throughout 2010 as we operated in an income trust structure. The Restricted Options, Share Rights and subsequent grants under the Option Plan receive equity treatment for accounting purposes subsequent to our conversion to a corporation 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 new option grants are calculated using a Black-Scholes option-pricing model and a Binomial Lattice option-pricing model continues to be used to value the Share Rights. The Restricted Rights are accounted for as a liability as holders may elect to settle in cash or common shares.

On January 1, 2011, the previously recognized trust unit rights 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 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)	**2011**	2010	2009
Options	**$ 18**	$ —	$ —
Restricted Options	**22**	—	—
Restricted Rights	**(29)**	—	—
Share Rights	**1**	—	—
LTRIP	**14**	8	—
TURIP	**—**	151	52
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	**$ 84**	$ 159	$ 52

The share price used in the fair value calculation of the LTRIP liability and Restricted Rights obligation at December 31, 2011 was $20.19 (2010 – $23.84 and 2009 – N/A).

General and Administrative Expenses ("G&A")

(millions, except per boe amounts)	Year ended December 31		
	2011	2010	2009
Gross	**$ 222**	$ 207	$ 189
Per boe	**3.72**	3.45	2.93
Net	**142**	145	129
Per boe	**$ 2.38**	$ 2.41	$ 1.99

For 2011, our staff levels continued to increase compared to 2010 as we transitioned to an E&P production company resulting in higher gross costs.

In 2010 we began increasing our complement of technical staff and consolidated our employees into one building prior to our conversion to an E&P company which led to higher staff and building occupancy costs in 2010 compared to 2009.

Depletion, Depreciation and Accretion

(millions, except per boe amounts)	Year ended December 31		
	2011	2010	2009
Depletion and depreciation ("D&D")	**$ 1,158**	$ 1,169	$ 1,514
D&D expense per boe	**19.45**	19.44	23.39
Accretion of decommissioning liability	**45**	44	42
Accretion expense per boe	**$ 0.76**	$ 0.73	$ 0.65

D&D and accretion rates were comparable in 2011 and 2010. In 2009, under previous GAAP, depletion was based on proved reserves which resulted in a higher rate.

During the first quarter of 2011, we recorded an impairment reversal of $39 million (2010 – none) to reflect stronger commodity prices resulting in higher forecast cash flows relating to properties in central Alberta. In the second quarter of 2011, we recorded a $29 million impairment (2010 – $80 million) on certain properties in central Alberta due to weaker forward commodity prices.

Taxes

(millions)	Year ended December 31		
	2011	2010	2009
Deferred tax recovery	**$ (227)**	$ (101)	$ (378)

The 2011 deferred tax recovery includes a $304 million recovery related to the tax rate differential on our conversion from a trust to an E&P company. As a corporation, we are subject to income taxes at Canadian corporate tax rates. In the trust structure, under IFRS we were required 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. The comparative figure in 2009 included a $168 million recovery related to unrealized risk management losses and a $65 million recovery related to income tax legislation enacted by the Government of Canada which reduced the provincial component of the Specified Investment Flow-Through ("SIFT") tax rate from 13 percent to 10 percent.

We currently have a significant tax pool base. Based on current commodity prices and capital spending plans, we forecast these pools will shelter our taxable income for an extended period.

Tax Pools

(millions)	As at December 31 2011	2010	2009
Undepreciated capital cost (UCC)	**$ 1,085**	$ 1,122	$ 1,379
Canadian oil and gas property expense (COGPE)	**1,395**	1,562	1,912
Canadian development expense (CDE)	**2,104**	1,494	1,141
Canadian exploration expense (CEE)	**294**	305	280
Non-capital losses	**2,966**	2,481	2,139
Other	**31**	31	16
Total	**$ 7,875**	$ 6,995	$ 6,867

Tax pool amounts exclude income deferred in operating partnerships of $1,654 million in 2011 (2010 – $920 million and 2009 – $931 million).

Foreign Exchange

(millions)	Year ended December 31 2011	2010	2009
Unrealized foreign exchange loss (gain)	**$ 38**	$ (82)	$ (186)

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 losses during 2011 were primarily due to the weakening of the Canadian dollar relative to the US dollar and the gains during 2010 and 2009 were primarily due to the strengthening of the Canadian dollar relative to the US dollar.

Funds Flow and Net Income (Loss)

	Year ended December 31 2011	2010	2009
Funds flow [1] (millions)	**$ 1,537**	$ 1,185	$ 1,493
Basic per share	**3.29**	2.68	3.62
Diluted per share	**3.29**	2.65	3.60
Net income (loss) (millions)	**638**	1,110	(144)
Basic per share	**1.37**	2.51	(0.35)
Diluted per share	**$ 1.36**	$ 2.48	$ (0.35)

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

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 2010, funds flow was lower than 2009 primarily as a result of net property dispositions and lower realized risk management gains.

For 2011, net income decreased compared to 2010 as significant gains on asset dispositions were recorded in 2010, which included a $368 million gain on the formation of the Cordova Joint Venture and a $572 million after-tax gain on the formation of the Peace River Oil Partnership. This was partially offset by a $304 million deferred tax recovery related to our conversion from an income trust to a corporate structure. The increase in net income in 2010 from 2009 was due to the gains on asset dispositions in 2010.

	Year ended December 31					
	2011		2010		2009	
	per boe	**%**	per boe	%	per boe	%
Oil and natural gas revenues [1]	**$ 60.54**	**100**	$ 50.46	100	$ 50.67	100
Royalties	**(11.09)**	**(18)**	(9.07)	(18)	(7.66)	(15)
Operating expenses [2]	**(17.40)**	**(29)**	(15.71)	(31)	(14.93)	(30)
Transportation	**(0.49)**	**(1)**	(0.55)	(1)	(0.52)	(1)
Net operating income	**31.56**	**52**	25.13	50	27.56	54
General and administrative expenses	**(2.38)**	**(4)**	(2.41)	(5)	(1.99)	(4)
Share-based compensation – cash	**(0.15)**	**—**	(0.14)	—	—	—
Financing [3]	**(3.20)**	**(5)**	(2.89)	(6)	(2.49)	(5)
Funds flow	**25.83**	**43**	19.69	39	23.08	45
Unrealized foreign exchange gain (loss)	**(0.64)**	**(1)**	1.36	3	2.88	6
Share-based compensation	**(1.26)**	**(2)**	(2.51)	(5)	(0.81)	(2)
Risk management activities [4]	**0.55**	**1**	0.40	1	(9.17)	(18)
Depletion and depreciation	**(19.45)**	**(32)**	(19.44)	(39)	(23.39)	(46)
Accretion	**(0.76)**	**(1)**	(0.73)	(1)	(0.65)	(1)
Gain on dispositions	**2.89**	**5**	18.02	36	—	—
Exploration and evaluation	**(0.25)**	**(1)**	(0.02)	—	—	—
Deferred tax recovery	**3.80**	**6**	1.70	3	5.84	12
Net income (loss)	**$ 10.71**	**18**	$ 18.47	37	$ (2.22)	(4)

(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.

Capital Expenditures

	Year ended December 31		
(millions)	**2011**	2010	2009
Land acquisition and retention	**$ 181**	$ 102	$ 19
Drilling and completions	**1,217**	800	286
Facilities and well equipping	**521**	281	336
Geological and geophysical	**9**	10	9
Corporate	**25**	11	38
Capital expenditures [1]	**1,953**	1,204	688
Joint venture, carried capital	**(107)**	(17)	—
Property dispositions, net	**(266)**	(1,306)	(369)
Capital expenditures, net	**1,580**	(119)	319
Business combinations	**286**	139	116
Total expenditures	**$ 1,866**	$ 20	$ 435

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

In 2011, we increased our capital program as we transitioned some of our light-oil plays from the appraisal phase into full-scale development which led to an increase in drilling and completions, facilities and well equipping capital costs. We were also successful at land sales and acquired strategic lands to complement our existing asset base.

During 2010, we increased our capital spending compared to 2009 to take advantage of success at our light-oil resource plays and in preparation for our conversion to an E&P company. This resulted in an increase in drilling and completions expenditures year-over-year.

Drilling

	Year ended December 31			
	2011			2010
	Gross	**Net**	Gross	Net
Oil	**457**	**353**	351	245
Natural gas	**53**	**36**	53	38
Dry	**—**	**—**	3	2
	510	**389**	407	285
Stratigraphic and service	**89**	**37**	54	34
Total	**599**	**426**	461	319
Success rate [1]		**100%**		99%

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

Gain on asset dispositions

	Year ended December 31		
(millions)	**2011**	2010	2009
Gain on asset dispositions	**$172**	$1,082	$—

During 2011, we closed property dispositions which resulted in gains of $172 million recognized in income (2010 – $1,082 million). In June 2010, as a result of forming the Peace River Oil Partnership, we recognized a pre-tax gain of $749 million in income and in September 2010, due to entering the Cordova Joint Venture, we recognized a $368 million gain.

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

	Year ended December 31		
(millions)	**2011**	2010	2009
E&E capital expenditures	**$ 321**	$ 58	$ —

Our E&E capital expenditures increased due to strategic land purchases and exploration and evaluation activities since our conversion to an E&P company. Included in E&E capital expenditures is the benefit of $92 million of joint venture carried capital in 2011 (2010 – nil). During 2011, we transferred $14 million from E&E into PP&E and we had a non-cash E&E expense of $15 million (2010 – $1 million) related to land expiries and unsuccessful exploration activities.

In 2011, we disposed of E&E assets valued at $2 million (2010 – $61 million) in connection with property dispositions.

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.

Sifton Energy Inc. ("Sifton") business combination

On December 22, 2010, we closed the acquisition of Sifton, a private oil and gas exploration company with assets primarily located in the Cardium light-oil resource play in central Alberta. The total acquisition cost was approximately $108 million, which included the assumption of approximately $23 million of debt and working capital.

Cordova Joint Venture

In the third quarter of 2010, we closed a joint venture agreement with a subsidiary of Mitsubishi Corporation (“Mitsubishi”) to develop our shale gas assets in the Cordova Embayment and certain conventional gas assets at our Wildboy property in northeastern British Columbia. As part of the arrangement, we sold a 50 percent interest in these assets to Mitsubishi in exchange for approximately $250 million of cash and approximately $205 million of future commitments. Mitsubishi will fund $600 million of the first $800 million of capital expenditures in this joint venture and we will continue to serve as the operator of the assets.

Peace River Oil Partnership

In the second quarter of 2010, we closed the transaction creating the Peace River Oil Partnership to develop oil resources in the Peace River area of northern Alberta. We contributed assets valued at $1.8 billion, retained a 55 percent interest in the partnership and received approximately $817 million which included $312 million cash paid upon closing and $505 million committed to us to fund our share of future capital and operating expenses for the Peace River Oil Partnership. As a result, on the first $1.0 billion of capital and operating costs to be incurred by the partnership, we will contribute approximately $56 million while maintaining our 55 percent interest in the partnership. In addition, we closed a private placement issuing approximately 23.5 million trust units to our partner for gross proceeds of $435 million ($424 million net).

January 2010 Asset Swap

In the first quarter of 2010, we closed an Asset Exchange Agreement increasing our position in our light-oil resource plays at Pembina and Dodsland with total production of approximately 560 boe per day in exchange for certain interests in the Leitchville area with total production of approximately 3,500 boe per day. Additionally, we received net cash proceeds of approximately $434 million which were applied to our bank facility.

Goodwill

	Year ended December 31		
(millions)	**2011**	2010	2009
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. We determined there was no goodwill impairment at December 31, 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 assumptions, become material.

We are dedicated to reducing the environmental impact from our operations through our environmental programs which include resource conservation, CO_2 sequestration, water management and site abandonment/reclamation. Operations are continuously monitored to minimize the environmental impact and sufficient 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 2011	%	2010	%	2009	%
Common shares issued, at market (1)	**$ 9,517**	**72**	$ 10,959	78	$ 7,821	69
Bank loans and long-term notes	**3,219**	**24**	2,496	18	3,219	28
Convertible debentures	**—**	**—**	255	2	255	2
Working capital deficiency (2)	**554**	**4**	303	2	106	1
Total enterprise value	**$ 13,290**	**100**	$ 14,013	100	$ 11,401	100

(1) The share price at December 31, 2011 was $20.19 (2010—$23.84 and 2009—$18.55).
(2) Excludes the current portion of risk management, convertible debentures and share-based compensation liability.

For 2011, we declared total dividends of $506 million or $1.08 per share (2010 – trust distributions of $686 million or $1.56 per unit and 2009 – $841 million or $2.04 per unit) and paid total dividends, including amounts funded by the dividend reinvestment plan, of $420 million (2010 – trust distributions of $708 million and 2009 – $910 million). On February 15, 2012, our Board of Directors declared a 2012 first quarter dividend of $0.27 per share to be paid on April 13, 2012 to shareholders of record on March 30, 2012. Shareholders are advised that this dividend is designated as an “eligible dividend” for Canadian income tax purposes.

On June 27, 2011, the Company closed the extension of its unsecured, revolving, syndicated bank facility with an aggregate borrowing limit of $2.25 billion and a four-year term. On October 27, 2011, the Company increased the aggregate borrowing limit by $500 million to $2.75 billion using the “accordion” feature in the facility. For further details on its debt instruments, please refer to the “Financing” and “Convertible Debentures” sections of this MD&A.

We actively manage our debt portfolio and consider opportunities to reduce or diversify our debt structure. We actively consider 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. These actions and plans 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, 2011, the Company was in compliance with all of these financial covenants which comprise the following:

	Limit	December 31, 2011
Senior debt to EBITDA (1)	Less than 3:1	**1.86**
Total debt to EBITDA (1)	Less than 4:1	**1.86**
Senior debt to capitalization	Less than 50%	**26%**
Total debt to capitalization	Less than 55%	**26%**

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

As at December 31, 2011, 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.

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 expenditure requirements. Our dividend level could change based on these and other factors and is subject to the approval of our Board of Directors.

Convertible Debentures

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. We now have no convertible debentures outstanding.

Financial Instruments

We had the following financial instruments outstanding as at December 31, 2011. 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	60,000 bbls/d	Jan/12 – Dec/12	US$85.53 to $101.16/bbl	$ (103)
WTI Collars	5,000 bbls/d	Jan/13 – Dec/13	US$90.00 to $100.00/bbl	(1)
Natural gas				
AECO Forwards (1)	52,730 GJ/d	Jan/12 – Dec/12	$4.08/GJ	25
Electricity swaps				
Alberta Power Pool	45 MW	Jan/12 – Dec/12	$53.02/MWh	7
Alberta Power Pool	30 MW	Jan/12 – Dec/13	$54.60/MWh	10
Alberta Power Pool	20 MW	Jan/13 – Dec/13	$56.10/MWh	2
Alberta Power Pool	50 MW	Jan/14 – Dec/14	$58.50/MWh	1
Interest rate swaps	$650	Jan/12 – Jan/14	2.65%	(22)
Foreign exchange forwards on revenues				
12-month initial term	US$1,872	Jan/12 – Dec/12	1.022 CAD/USD	2
Foreign exchange forwards on senior notes				
3 to 15-year initial term	US$641	2014 – 2022	1.000 CAD/USD	20
Cross currency swaps				
10-year initial term	£57	2018	2.0075 CAD/GBP, 6.95%	(26)
10-year initial term	£20	2019	1.8051 CAD/GBP, 9.15%	(5)
10-year initial term	€10	2019	1.5870 CAD/EUR, 9.22%	(3)
Total				$ (93)

(1) The forward contracts total approximately 50,000 mcf per day with an average price of $4.30 per mcf.

Subsequent to December 31, 2011, we entered into additional crude oil collars on 30,000 barrels per day in 2013 between US$94.17 and US$109.23 per barrel.

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

Outlook

This outlook section is included to provide shareholders with information about our expectations as at March 15, 2012 for production and capital expenditures for 2012 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”.

Our production and capital guidance for 2012 remains unchanged. Taking into account net acquisition and disposition activity to date in 2012, our forecast average production for 2012 is between 168,500 and 172,500 boe per day and our exploration and development capital, net of acquisition and disposition activity, is forecasted to be in the range of $1.3 billion to $1.4 billion. These ranges are consistent with our prior forecasts for 2012 released with our third and fourth quarter 2011 results, reflecting acquisition and disposition activity to date in 2012, and filed on SEDAR at www.sedar.com.

Sensitivity Analysis

Estimated sensitivities to selected key assumptions on reported financial results 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	32	0.07
Liquids production	1,000 bbls/day	22	0.05
Price per mcf of natural gas	$0.10	9	0.02
Natural gas production	10 mmcf/day	—	—
Effective interest rate	1%	7	0.01
Exchange rate ($US per $CAD)	$0.01	19	0.04

Contractual Obligations and Commitments

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

(millions)	**2012**	2013	2014	2015	2016	Thereafter
Long-term debt	**$ —**	$ 5	$ 61	$ 1,504	$ 221	$ 1,428
Transportation	**23**	19	12	8	3	—
Transportation ($US)	**4**	4	37	37	33	231
Power infrastructure	**32**	15	15	15	15	14
Drilling rigs	**26**	26	22	16	10	2
Purchase obligations (1)	**13**	13	11	10	2	5
Interest obligations	**161**	161	158	127	93	216
Office lease (2)	**68**	66	60	60	59	479
Decommissioning liability (3)	**$ 70**	$ 67	$ 64	$ 61	$ 58	$ 287

(1) These amounts represent estimated commitments of $40 million for CO_2 purchases and $14 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 $434 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 26, 2015. If we are not successful in renewing or replacing the facility, we could enter other loans including term bank loans or be required to repay all amounts then outstanding on the facility. In addition, we have an aggregate of $2.0 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.

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

Equity Instruments

Common shares issued:	
As at December 31, 2011	471,372,730
Issued on exercise of share rights	162,988
Issued pursuant to dividend reinvestment plan	1,364,540
As at March 15, 2012	472,900,258
Options outstanding:	
As at December 31, 2011	7,919,600
Granted	7,548,200
Forfeited	(112,541)
As at March 15, 2012	15,355,259
Share Rights outstanding:	
As at December 31, 2011	2,549,112
Exercised	(155,841)
Forfeited	(104,283)
As at March 15, 2012	2,288,988
Restricted Options outstanding [(1)]:	
As at December 31, 2011	17,110,193
Forfeited	(3,916,374)
As at March 15, 2012	13,193,819

(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 2011 Highlights

Key financial and operational results for the fourth quarter 2011 were as follows:

	Three months ended December 31		
	2011	2010	% change
Financial (millions, except per share amounts)			
Gross revenues [1]	**$ 979**	$ 782	25
Funds flow	**437**	305	43
Basic per share	**0.93**	0.67	39
Diluted per share [2]	**0.93**	0.66	41
Net loss [2]	**(62)**	(37)	68
Basic per share [2]	**(0.13)**	(0.08)	63
Diluted per share [2]	**(0.13)**	(0.08)	63
Capital expenditures, net [3]	**583**	469	24
Dividends paid [4]	**$ 127**	$ 123	3
Operations			
Daily production			
Light oil and NGL (bbls/d)	**90,185**	88,447	2
Heavy oil (bbls/d)	**17,886**	16,849	6
Natural gas (mmcf/d)	**364**	365	—
Total production (boe/d)	**168,801**	166,148	2
Average sales price			
Light oil and NGL (per bbl)	**$ 88.76**	$ 71.05	25
Heavy oil (per bbl)	**76.88**	61.87	24
Natural gas (per mcf)	**$ 3.47**	$ 3.79	(8)
Netback per boe			
Sales price	**$ 63.05**	$ 52.43	20
Risk management loss	**(0.84)**	(1.51)	(44)
Net sales price	**62.21**	50.92	22
Royalties	**(11.47)**	(9.14)	25
Operating expenses	**(17.48)**	(15.92)	10
Transportation	**(0.48)**	(0.52)	(8)
Netback	**$ 32.78**	$ 25.34	29

(1) Gross revenues include realized gains and losses on commodity contracts.
(2) Comparative figures have been revised to comply with IFRS.
(3) Excludes business combinations.
(4) 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 increased in the fourth quarter of 2011 compared to 2010 primarily due to an increase in our light-oil production and higher crude oil prices. This also contributed to an increase in funds flow in 2011 compared to 2010.

The increase in net loss in 2011 from the prior period was primarily due to unrealized risk management losses.

We continued our oil focused capital program during the fourth quarter of 2011 and drilled 108 net wells.

Operations

Production in the fourth quarter of 2011 was 168,801 boe per day. We completed a successful capital program in the second half of 2011. We gained momentum in the third quarter after the fires and floods reaching our full operating capacity in the fourth quarter. Average oil and liquids production was approximately 108,000 barrels per day in the fourth quarter of 2011, an increase of seven percent over the third quarter of 2011. To date in 2012, we have closed property dispositions for proceeds of approximately $340 million.

During the fourth quarter of 2011, crude oil prices averaged WTI US$94.02 per barrel compared to WTI US$89.81 per barrel in the third quarter of 2011 and WTI US$85.18 per barrel in the fourth quarter of 2010. In the fourth quarter of 2011, the AECO Monthly Index averaged $3.47 per mcf compared to $3.72 per mcf in the third quarter of 2011 and $3.58 per mcf in the fourth quarter of 2010.

Netbacks were $32.78 per boe compared to $25.34 per boe in the fourth quarter of 2010. The increase was primarily due to higher crude oil prices.

Disclosure Controls and Procedures

As of December 31, 2011, 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, 2011 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. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by Penn West in the reports that it files or submits under the Exchange Act or under Canadian securities legislation is accumulated and communicated to the Company’s management, including the senior executive and financial officers, as appropriate to allow timely decisions regarding the required disclosure.

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”). We became a registrant under the U.S. Securities Exchange Act of 1934 and listed our trust units on the New York Stock Exchange in June 2006. As of December 31, 2011, 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, 2011 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 2011 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, 2011 that have materially affected, or are reasonably likely to materially affect, our ICOFR.

Changes in accounting policies

Transition to IFRS

On January 1, 2011, we completed our changeover to IFRS, with a transition date of January 1, 2010. On the transition date, we adjusted our account balances to IFRS and our financial reporting was changed to be in accordance with IFRS thereafter. A full description of our new accounting policies is outlined in Note 3 to our audited consolidated financial statements. Additionally, transition date information and reconciliations between IFRS and previous GAAP for comparative periods in 2010 are described in Note 24 to our audited consolidated financial statements. The transition to IFRS has not led to any changes in the business operations, capital strategies or funds flow of the Company.

Significant Accounting Differences and Accounting Policies

The following outlines significant accounting policy choices and differences between IFRS and previous GAAP applicable from the date of transition to IFRS on January 1, 2010. We operated in an income trust structure from the date of transition until our conversion to a corporation on January 1, 2011.

Component accounting

Under IFRS, depletion and depreciation of property, plant and equipment ("PP&E") is based on significant components. These components consist of oil and natural gas assets, facilities, turnarounds and corporate assets.

Depletion and depreciation

Under previous GAAP, PP&E was generally depleted based on aggregations at the country level using the full cost method of accounting for oil and natural gas activities. Depletion of resource properties and facilities will continue to be calculated using the unit-of-production method; however, under IFRS there is an option to use reserves volumes on a total proved or total proved plus probable basis. We have elected to deplete resource properties using total proved plus probable reserves. Other assets, consisting of computer hardware and software, office furniture, buildings and leasehold improvements, will be depreciated on a straight-line basis over their estimated useful lives.

E&E assets

Oil and natural gas properties are classified as either PP&E or E&E under IFRS. Under previous GAAP, oil and gas assets were classified only as PP&E. E&E assets consist of capital costs related to prospective assets for which the technical and commercial viability of extracting oil and natural gas has not yet been ascertained. These assets are initially measured at cost and classified according to the nature of the associated expenditures.

E&E costs are transferred to PP&E, to the extent they are not impaired, once their technical and commercial viability is established which will generally be 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 future plans for development activity, E&E assets are assessed for impairment. Any impairment will be charged to income as E&E expense.

Impairment of oil and natural gas properties

Under IFRS, impairment testing is performed at a lower level than under previous GAAP. As a consequence, impairment provisions are more likely to occur as properties will no longer be tested at the country level. Under IFRS, unlike previous GAAP, impairments other than goodwill impairments may be reversed in the event future conditions change.

Classification of trust units

Under previous GAAP, trust units were classified as equity instruments. Under IFRS, trust units carried a number of features that could result in either equity or liability treatment. Under IFRS "puttable financial instruments" with characteristics similar to ordinary shares are treated as equity instruments. We concluded that the appropriate classification of our trust units was equity.

Share-based payments

Under previous GAAP, share-based payments were classified as equity awards and were expensed using the straight-line method. Under IFRS, as an income trust, our equity awards met the definition of a puttable financial instrument, thus the awards were considered a liability in 2010 and expensed on a graded vesting schedule.

Asset retirement obligations ("ARO") or decommissioning liability

Under previous GAAP, ARO was recorded when there was a legal obligation to abandon an asset. Under IFRS, a decommissioning liability is recorded when there is either a legal or constructive obligation to abandon an asset.

Future (deferred) income tax

While operating as an income trust subsequent to 2006, Penn West was considered a Specified Investment Flow-Through entity (a "SIFT entity"). Under previous GAAP, income tax assets and liabilities at the trust level were measured at the enacted tax rate for SIFT entities of approximately 25 percent. Under IFRS, in the 2010 period preceding our conversion to a corporation we were required to apply a tax rate of 39 percent, representing the rate applicable to undistributed profits of the Trust in the Province of Alberta.

IFRS 1—Oil and Gas Exemption

In July 2009, the International Accounting Standards Board ("IASB") issued amendments to IFRS 1 "First-time adoption of IFRS" allowing additional exemptions for first-time adopters. Under these amendments, oil and natural gas companies previously following the full cost method of accounting could elect to use the recorded amount under a previous GAAP as the deemed cost for oil and gas assets on the transition date to IFRS. We elected to apply this exemption. For a further discussion on IFRS 1 exemptions, refer to Note 24 of our audited consolidated financial statements.

Future Accounting Pronouncements

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

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.

IFRS impacts subsequent to our corporate conversion

Shareholders’ capital

Following the one-to-one exchange of trust units for common shares on January 1, 2011, Unitholders’ Capital was re-classified to Shareholders’ Capital.

Elimination of the consolidated deficit

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 was eliminated against share capital on January 1, 2011.

Deferred Tax

Effective January 1, 2010, as an income trust, we were required to measure deferred income tax assets and liabilities at the trust level at a tax rate of 39 percent, representing the tax rate applicable to undistributed profits of the trust in the Province of Alberta. Deferred income tax was recorded on this basis from January 1, 2010 until our conversion to a corporation on January 1, 2011. Under IFRS, upon conversion to a corporation, the deferred income tax assets and liabilities were re-measured at the applicable corporate income tax rate of approximately 26 percent and the company recognized a $304 million deferred income tax recovery during the first quarter of 2011.

Share-based Compensation

Effective January 1, 2011, we implemented an Option Plan and amended our TURIP to become the CSRIP. Trust unit right holders had the choice to receive both a Restricted Option and a Restricted Right for outstanding “in-the-money” trust unit rights or receive a Share Right under the CSRIP if they chose not to elect or had “out-of-the-money” trust unit rights. The elimination of the TURIP and subsequent implementation of the Option Plan and CSRIP resulted in a $58 million net charge to income during the first quarter of 2011.

Related-Party Transactions

During 2011, we incurred $1 million (2010 – $2 million) of legal fees from a law firm of which a partner is also a director of Penn West.

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 the audited consolidated financial statements under IFRS. In the determination of financial results, we must make certain critical accounting estimates as follows:

Depletion and Impairments

Costs for 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 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 a key 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 determined there was no impairment at December 31, 2011.

Decommissioning Liability

The discounted expected future cost of statutory, contractual, legal or constructive obligations to retire long-lived assets is recorded as a decommissioning liability 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 11 to the 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 10 to the 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, collars or other financial instruments may be utilized from time to time. Collars ensure that commodity prices realized will fall into a contracted range for a contracted sales volume. Forward power contracts fix a portion of future electricity costs at levels determined to be economic by management.

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. Penn West determined there was no goodwill impairment at December 31, 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: certain disclosures contained under the headings "Business Strategy" and "Outlook" relating to, among other things, our continued focus in 2012 on light-oil plays and our further shift toward full-scale development across portions of these plays; certain disclosures contained under the heading "Business Strategy" relating to, among other things, our continued application of horizontal multi-stage drilling technologies and pad drilling techniques, our continued appraisal activities under the Peace River Oil Partnership and the Cordova Joint Venture, our intention to appraise and extend our portfolio of light-oil and liquids-rich gas plays at a less aggressive pace than in 2010 and 2011; forecasts for modest global GDP growth in 2012 and the expected incremental demand for crude oil as a result thereof; our intention to continually allocate substantially all of our capital investments to oil projects; certain disclosures contained under the heading "Outlook" relating to our estimated 2012 exploration and development capital program and our resulting production estimates for 2012; certain disclosures contained under the heading "Natural Gas" relating to, among other things, our view of the outlook for natural gas prices and supply-demand fundamentals for such commodity; our forecast under the heading "Taxes" that, based on current commodity prices and capital spending plans, our tax pool base will shelter our taxable income for an extended period; all matters relating to our dividend policy, including the factors that may affect the amount of dividends that we pay in the future (if any); the ability of our debt and risk management programs to increase the likelihood that we can maintain our financial flexibility to capture opportunities available in the markets in addition to the continuation of our capital and dividend programs and the longer-term execution of our business strategies; and certain disclosures contained under the heading "Sensitivity Analysis" relating to our estimated sensitivities to certain key assumptions on 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; future capital expenditure levels; future crude oil, natural gas liquids and natural gas production levels; drilling results; future exchange rates and interest rates; the amount of future cash dividends that we intend to pay; 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, including the completed acquisitions discussed herein; geological, technical, drilling and processing problems; general economic conditions in Canada, the U.S. and globally; 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 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; uncertainty of obtaining required approvals for acquisitions 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 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.

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.



Murray R. Nunns
President & CEO



Todd H. Takeyasu
Executive Vice President and CFO

March 15, 2012

INDEPENDENT AUDITORS' REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

To the 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, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of income (loss), statements of changes in shareholders' equity and statements of cash flows for the years ended December 31, 2011 and 2010, 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.

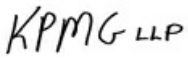
We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinions.

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, 2011, December 31, 2010 and January 1, 2010 and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 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, 2011, 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 15, 2012 expressed an unmodified (unqualified) opinion on the effectiveness of Penn West Petroleum Ltd.'s internal control over financial reporting.



KPMG LLP
Chartered Accountants
Calgary, Canada
March 15, 2012

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 ("the Company") internal control over financial reporting as of December 31, 2011, based on the 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, 2011, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have conducted our audits on the consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Our report dated March 15, 2012 expressed an unqualified opinion on those consolidated financial statements.



KPMG LLP
Chartered Accountants
Calgary, Canada
March 15, 2012

Penn West Petroleum Ltd.
Consolidated Balance Sheets

(CAD millions)	Note	December 31, 2011	December 31, 2010 (Note 24)	January 1, 2010 (Note 24)
Assets				
Current				
Accounts receivable	4	**$ 486**	$ 386	$ 371
Other	4	**104**	87	101
Risk management	12	**39**	23	29
		629	496	501
Non-current				
Deferred funding assets	5	**596**	678	—
Exploration and evaluation assets	6	**418**	128	132
Property, plant and equipment	7	**11,893**	11,218	11,174
Goodwill	8	**2,020**	2,020	2,020
Risk management	12	**28**	3	10
		14,955	14,047	13,336
Total assets		**$ 15,584**	$ 14,543	$ 13,837
Liabilities and Shareholders' Equity				
Current				
Accounts payable and accrued liabilities	4	**$ 1,108**	$ 910	$ 568
Dividends payable		**127**	41	63
Convertible debentures	9	**—**	255	18
Risk management	12	**114**	85	159
		1,349	1,291	808
Non-current				
Long-term debt	10	**3,219**	2,496	3,219
Convertible debentures	9	**—**	—	255
Decommissioning liability	11	**607**	648	562
Risk management	12	**46**	67	31
Deferred tax liability	13	**1,287**	1,452	1,530
Other non-current liabilities	15	**9**	29	15
		6,517	5,983	6,420
Shareholders' equity				
Shareholders' capital	14	**8,840**	—	—
Unitholders' capital	14	**—**	9,170	8,451
Other reserves	14	**95**	—	—
Retained earnings (deficit)		**132**	(610)	(1,034)
		9,067	8,560	7,417
Total liabilities and shareholders' equity		**$ 15,584**	$ 14,543	$ 13,837

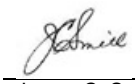
Subsequent events (Notes 12 and 16)
Commitments and contingencies (Note 21)

See accompanying notes to the consolidated financial statements.

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



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 2011	2010 (Note 24)
Oil and natural gas sales		**$ 3,667**	$ 3,054
Royalties		**(661)**	(545)
		3,006	2,509
Risk management gain (loss)			
Realized		**(63)**	(20)
Unrealized	12	**8**	23
		2,951	2,512
Expenses			
Operating		**1,036**	944
Transportation		**29**	33
General and administrative		**142**	145
Share-based compensation	15	**84**	159
Depletion and depreciation	7	**1,158**	1,169
Gain on dispositions		**(172)**	(1,082)
Exploration and evaluation	6	**15**	1
Unrealized risk management gain	12	**(25)**	(2)
Unrealized foreign exchange loss (gain)		**38**	(82)
Financing	9,10	**190**	174
Accretion	11	**45**	44
		2,540	1,503
Income before taxes		**411**	1,009
Deferred tax recovery	13	**(227)**	(101)
Net and comprehensive income		**$ 638**	$ 1,110
Net income per share			
Basic	17	**$ 1.37**	$ 2.51
Diluted	17	**$ 1.36**	$ 2.48
Weighted average shares outstanding (millions)			
Basic	17	**467.2**	441.8
Diluted	17	**467.4**	451.6

See accompanying notes to the consolidated financial statements.

Penn West Petroleum Ltd.
Consolidated Statements of Cash Flows

(CAD millions)	Note	Year ended December 31 2011	2010
Operating activities			
Net income		**$ 638**	$ 1,110
Depletion and depreciation		**1,158**	1,169
Gain on dispositions		**(172)**	(1,082)
Exploration and evaluation		**15**	1
Accretion		**45**	44
Deferred tax recovery		**(227)**	(101)
Share-based compensation		**75**	151
Unrealized risk management gain		**(33)**	(25)
Unrealized foreign exchange loss (gain)		**38**	(82)
Decommissioning expenditures		**(81)**	(53)
Change in non-cash working capital	18	**(49)**	85
		1,407	1,217
Investing activities			
Capital expenditures		**(1,846)**	(1,187)
Acquisitions		**(138)**	(552)
Proceeds from dispositions		**404**	1,148
Business combinations		**(166)**	(85)
Change in non-cash working capital	18	**113**	155
		(1,633)	(521)
Financing activities			
Increase (decrease) in bank loan		**475**	(1,101)
Proceeds from issuance of notes		**212**	460
Repayment of acquired credit facilities		**(39)**	(21)
Issue of equity		**161**	557
Dividends and distributions paid		**(328)**	(591)
Settlement of convertible debentures	9	**(255)**	—
		226	(696)
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	Retained Earnings	Total
Balance at January 1, 2011		$ 9,170	$ —	$ (610)	$ 8,560
Elimination of deficit	14	(610)	—	610	—
Net and comprehensive income		—	—	638	638
Implementation of Option Plan and CSRIP	15	—	81	—	81
Share-based compensation	15	—	41	—	41
Issued on exercise of options and share rights	14	188	(27)	—	161
Issued to dividend reinvestment plan	14	92	—	—	92
Dividends declared		—	—	(506)	(506)
Balance at December 31, 2011		**$ 8,840**	**$ 95**	**$ 132**	**$ 9,067**

(CAD millions)	Note	Unitholders' Capital	Other Reserves	Deficit	Total
Balance at January 1, 2010	24	$ 8,451	$ —	$ (1,034)	$ 7,417
Net and comprehensive income		—	—	1,110	1,110
Issued on exercise of trust unit rights	14	114	—	—	114
Issued to employee trust unit savings plan	14	42	—	—	42
Issued to distribution reinvestment plan	14	117	—	—	117
Issued to settle convertible debentures	14	18	—	—	18
Issued on trust unit placement	14	428	—	—	428
Distributions declared		—	—	(686)	(686)
Balance at December 31, 2010		$ 9,170	$ —	$ (610)	$ 8,560

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 12)

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 or 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. The consolidated results in 2011 are under Penn West's current structure as a conventional corporation and the comparative figures in 2010 were under Penn West's former structure as an income trust.

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. As this is the Company's first annual period reporting under IFRS, the guidelines under IFRS 1 "First-time Adoption of IFRS" have been applied as discussed in Note 24. Prior to 2011, Penn West prepared its audited annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("previous GAAP").

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 12.

The annual consolidated financial statements were approved for issuance by the Board of Directors on March 15, 2012.

b) Basis of Presentation

The annual consolidated financial statements include the accounts of Penn West and 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.

The following are the critical judgments that management has made in applying the Company's accounting policies and 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. 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 management's best estimate 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 which can vary from actual future events. The factors applied in the calculation are management's best 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, tax losses and other tax credits will reverse and the use of substantively enacted tax rates at the balance sheet date.

b) Business combinations

Penn West uses the acquisition method to account for business combinations. The net identifiable assets, liabilities and contingent assets and liabilities acquired in transactions which meet the definition of a business combination under IFRS are measured at their fair value at 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 allocation of fair values acquired during the measurement period being 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 fair value of 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. 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:

- Penn West has transferred the significant risks and rewards of ownership of the goods to the buyer;
- Penn West retains 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 share of these jointly controlled assets and liabilities and a 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 the assets. Penn West's share of jointly controlled assets and any liabilities incurred jointly with other parties are recognized in the consolidated financial statements to the extent of its proportionate interest. 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.

Penn West entered into the Peace River Oil Partnership on June 1, 2010. This arrangement is accounted for using the proportionate consolidation method with Penn West recognizing its 55 percent share of revenues, expenses, assets and liabilities. Please refer to Note 5 below.

f) Transportation expense

Transportation costs are paid by Penn West for the shipping of natural gas, crude oil and NGLs 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's and each of its subsidiaries' functional currency is the Canadian dollar. 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 future 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.

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.

Significant 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.

In assessing the value-in-use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value-in-use is computed as the present value of future cash flows expected to be derived from production of proved and probable reserves. Under the fair value less cost to sell method, various internal and external factors are used, which can include observable market conditions and transactions, to determine the recoverable amount.

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 and depreciation.

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 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 one 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 Rights") 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. 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 fair value of future obligations for property abandonment and site restoration is recognized as a decommissioning liability 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.

Preferred shares are classified as equity and may be issued in one or more series. Preferred shares of each series will rank on parity with the Preferred shares of other series with respect to accumulated dividends and return on capital. The Preferred shares take priority over the Common shares with respect to the payment of dividends or the distribution of assets, if required.

n) Earnings per share

Earnings per share is calculated by dividing net and comprehensive 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 pro forma exercise of in-the-money share options are used to purchase common shares at average market prices.

Penn West calculated the dilutive impact of the convertible debentures by assuming any outstanding debentures are converted at the later of the beginning of the period or the date of issue.

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 on the balance sheet upon initial recognition of the 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;
- 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, convertible debentures 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, 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, 2011, Penn West had no compound instruments outstanding.

s) Classification of debt or equity

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

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

In 2010, when Penn West was operating as a trust, its trust units were considered puttable financial instruments that met the criteria in IAS 32 "Financial Instruments: Presentation" and received equity classification.

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.

u) Comprehensive income

Comprehensive income is defined as the change in equity from transactions and other events from non-owner sources and consists of net income and other comprehensive income ("OCI"). OCI refers to items recognized in comprehensive income that are excluded from net income calculated in accordance with IFRS. Penn West has no items requiring separate disclosure as OCI on a statement of Comprehensive Income.

Future Accounting Pronouncements

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

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 currrently assessing the impact of this standard.

4. Working capital

	As at December 31	
	2011	2010
Components of accounts receivable		
Trade	**$ 130**	$ 70
Accruals	**356**	316
	$ 486	$ 386
Components of other assets		
Prepaid expenses	**$ 63**	$ 66
Other	**41**	21
	$ 104	$ 87
Components of accounts payable and accrued liabilities		
Accounts payable	**$ 296**	$ 168
Royalty payable	**91**	70
Capital accrual	**399**	285
Operating accrual	**161**	165
Share-based compensation accrual	**91**	175
Other	**70**	47
	$ 1,108	$ 910

Accounts receivable

Penn West continuously monitors credit risk and maintains credit policies to ensure collection risk is limited. Its 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 the 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
2011	**$ 411**	**$ 68**	**$ 7**	**$ 486**
2010	$ 313	$ 55	$ 18	$ 386

5. Deferred funding assets

Peace River Oil Partnership

In 2010, Penn West entered a partnership agreement to develop oil assets in the Peace River area of Alberta. Pursuant to the agreement, Penn West contributed assets with a fair value of $1.8 billion in exchange for a 55 percent interest in the partnership. Penn West received cash consideration of $312 million upon closing and received an additional $505 million in future commitments from its partner to fund Penn West's share of future capital and operating expenses in the Peace River Oil Partnership. As at December 31, 2011, approximately $421 million of deferred funding remained (2010 – $473 million).

Cordova Joint Venture

In 2010, Penn West entered into a joint venture agreement to develop its unconventional natural gas assets located in the Cordova Embayment and certain conventional assets located at its Wildboy play in northeastern British Columbia. Penn West sold a 50 percent interest in the assets for cash consideration of approximately $250 million upon closing and approximately $205 million in future commitments from its partner for Penn West's share of future capital costs in the joint venture. As at December 31, 2011, approximately $175 million of deferred funding remained (2010 – $205 million).

6. Exploration and evaluation assets

	Year ended December 31	
	2011	2010
Balance, beginning of year	**$ 128**	$ 132
Capital expenditures	**229**	58
Joint venture, carried capital	**92**	—
Expense	**(15)**	(1)
Transfers to PP&E	**(14)**	—
Net dispositions	**(2)**	(61)
Balance, end of year	**$ 418**	$ 128

On December 31, 2011 and 2010 no impairment existed related to exploration and evaluation assets. Also, an impairment test was completed on amounts reclassified into PP&E at which time the estimated fair value exceeded the carrying amount, thus, no impairment was noted.

7. Property, plant and equipment

Cost

	Oil and gas assets	Facilities	Turnarounds	Corporate assets	Total
Balance at January 1, 2010	$ 13,186	$ 4,476	$ 10	$ 90	$ 17,762
Capital expenditures	838	279	—	12	1,129
Joint venture, carried capital	17	—	—	—	17
Acquisitions	442	110	—	—	552
Dispositions	(1,022)	(114)	—	—	(1,136)
Business combinations	139	—	—	—	139
Net decommissioning additions	73	18	—	—	91
Balance at December 31, 2010	**$ 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**

Accumulated depletion and depreciation

	Oil and gas assets	Facilities	Turnarounds	Corporate assets	Total
Balance at January 1, 2010	$ 4,890	$ 1,659	$ 7	$ 32	$ 6,588
Depletion and depreciation	896	185	2	6	1,089
Dispositions	(379)	(42)	—	—	(421)
Impairments	62	18	—	—	80
Balance at December 31, 2010	**$ 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**

Net book value

	As at December 31	
	2011	2010
Total	**$ 11,893**	$ 11,218

In addition to Penn West's net share of capital overhead recoveries, capital additions included approximately $24 million of staff costs directly attributable to exploration and development activities (2010 – $24 million).

On December 31, 2011 and 2010, no impairment existed 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 (2010 – none) 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 used in the impairment test:

	WTI ($US/ bbl)	AECO ($CAD/mcf)	Exchange rate ($US equals $1 CAD)
2012	$ 97.53	$ 3.32	1.00
2013	97.45	3.95	1.00
2014	96.00	4.36	1.00
2015	98.71	5.29	1.00
2016 – 2021	$ 103.71	$ 6.07	1.00
Thereafter (inflation percentage)	2%	2%	1.00

8. Goodwill

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

A goodwill impairment test was completed at December 31, 2011 and 2010 at which time the recoverable amount exceeded the net asset value, thus, no impairment was recorded. The key assumptions used in determining the recoverable amount include the future cash flows using proved plus probable reserves discounted at 10 percent, the forecasted commodity prices, future development costs and the future reserve values estimated by the independent reserve engineers.

9. Convertible debentures

Penn West's outstanding balances and estimated fair values for the unsecured, subordinated convertible debentures were as follows:

	As at December 31	
	2011	2010
Total	**$ —**	$ 255
Total fair value [1]	**$ —**	$ 262

(1) Based on quoted market value.

At December 31, 2011, Penn West had no unsecured, subordinated convertible debentures outstanding. 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).

	PWT.DB.D –6.5%	PWT.DB.E –7.2%	PWT.DB.F –6.5%	Total
Balance, December 31, 2009	$ 18	$ 26	$ 229	$ 273
Matured [1]	(18)	—	—	(18)
Balance, December 31, 2010	$ —	$ 26	$ 229	$ 255
Settled [2]	—	(2)	(5)	(7)
Matured [2]	—	(24)	(224)	(248)
Balance, December 31, 2011	**$ —**	**$ —**	**$ —**	**$ —**

(1) Convertible debentures were settled in equity.
(2) Convertible debentures were settled in cash.

10. Long-term debt

	As at December 31	
	2011	2010
Bankers' acceptances and prime rate loans	**$ 1,248**	$ 773
U.S. Senior unsecured notes – 2007 Notes		
5.68%, US$160 million, maturing May 31, 2015	**163**	159
5.80%, US$155 million, maturing May 31, 2017	**158**	154
5.90%, US$140 million, maturing May 31, 2019	**142**	139
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	**155**	152
6.16%, CAD$30 million, maturing May 29, 2018	**30**	30
6.30%, US$278 million, maturing May 29, 2018	**283**	276
6.40%, US$49 million, maturing May 29, 2020	**50**	49
UK Senior unsecured notes – UK Notes		
6.95%, £57 million, maturing July 31, 2018 (1)	**90**	88
Senior unsecured notes – 2009 Notes		
8.29%, US$50 million, maturing May 5, 2014	**51**	50
8.89%, US$35 million, maturing May 5, 2016	**36**	35
9.32%, US$34 million, maturing May 5, 2019	**35**	34
8.89%, US$35 million, maturing May 5, 2019 (2)	**36**	35
9.15%, £20 million, maturing May 5, 2019 (3)	**32**	31
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	**28**	27
4.88%, CAD$50 million, maturing March 16, 2015	**50**	50
5.29%, US$65 million, maturing March 16, 2017	**66**	64
5.85%, US$112 million, maturing March 16, 2020	**114**	112
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	**86**	49
4.98%, US$18 million, maturing December 2, 2022	**18**	18
5.23%, US$50 million, maturing December 2, 2025	**51**	10
Senior unsecured notes – 2011 Q4 Notes		
3.64%, US$25 million, maturing November 30, 2016	**25**	—
4.23%, US$12 million, maturing November 30, 2018	**12**	—
4.63%, CAD$30 million, maturing November 30, 2018	**30**	—
4.79%, US$68 million, maturing November 30, 2021	**69**	—
Total long-term debt	**$ 3,219**	$ 2,496

(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.

The Company has a four-year, unsecured, revolving syndicated bank facility with an aggregate borrowing limit of $2.75 billion. The facility expires on June 26, 2015 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, 2011, the Company had approximately $1.5 billion of unused credit capacity available.

The interest rates on the balance of the Company's bank debt are subject to fluctuations in the short-term money market rates as bank debt is generally held in short-term, floating interest rate debt instruments. The weighted average interest rate at December 31, 2011 on long-term debt was 5.9 percent (2010 – 5.7 percent). As at December 31, 2011, 19 percent (2010 – none) of Penn West's long-term debt instruments were exposed to changes in short-term interest rates.

Letters of credit totalling $3 million were outstanding on December 31, 2011 (2010 – $2 million) that reduce the amount otherwise available to be drawn on the syndicated facility.

Financing costs, including interest expense on the syndicated bank facility, the senior unsecured notes and the convertible debentures, were $190 million for 2011 (2010 – $174 million). Also included in financing costs are realized losses on interest rate swaps of $12 million for 2011 (2010 – $21 million).

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

	As at December 31	
	2011	2010
2007 Notes	**$ 535**	$ 500
2008 Notes	**584**	557
UK Notes	**89**	87
2009 Notes	**242**	239
2010 Q1 Notes	**334**	309
2010 Q4 Notes	**239**	151
2011 Notes	**139**	—
Total	**$ 2,162**	$ 1,843

11. 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 (2010—2.0 percent) and the inflated amount was discounted using a credit-adjusted rate of 7.0 percent (2010—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 35 years. Future cash flows from operating activities are expected to fund the obligations.

Changes to the decommissioning liability were as follows:

	Year ended December 31	
	2011	2010
Balance, beginning of year	**$ 648**	$ 562
Net liabilities incurred (disposed) during the period [1]	**(19)**	54
Increase in liability due to change in estimate	**12**	37
Liabilities settled during the period	**(81)**	(53)
Liabilities acquired during the period	**2**	4
Accretion charges	**45**	44
Balance, end of year	**$ 607**	$ 648

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

12. Risk management

Financial instruments included in the balance sheets consist of accounts receivable, fair values of derivative financial instruments, current liabilities, convertible debentures and long-term debt. Except for the senior, unsecured notes described in Note 10 and the convertible debentures 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 2011 and 2010, 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	**2011**	2010	**2011**	2010
Accounts receivable	Loans and receivables	**$ 486**	$ 386	**$ 486**	$ 386
Derivative financial assets	FV through profit/loss	**67**	26	**67**	26
Derivative financial liabilities	FV through profit/loss	**160**	152	**160**	152
Accounts payable and accrued liabilities	Financial liabilities	**1,108**	910	**1,108**	910
Distributions payable	Financial liabilities	**127**	41	**127**	41
Convertible debentures	Financial liabilities	**—**	255	**—**	262
Bankers’ acceptances and prime rate loans	Financial liabilities	**1,248**	773	**1,248**	773
Senior notes [1]	Financial liabilities	**$ 1,971**	$ 1,723	**$ 2,162**	$ 1,843

(1) Calculated as the present value of the interest and principal payments at December 31, 2011.

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

Risk management asset (liability)	Year ended December 31 2011	2010
Balance, beginning of year	**$ (126)**	$ (151)
Unrealized gain (loss) on financial instruments:		
Commodity collars and swaps	**8**	23
Electricity swaps	**35**	8
Interest rate swaps	**(8)**	(3)
Foreign exchange forwards	**(4)**	16
Cross currency swaps	**2**	(19)
Total fair value, end of year	**$ (93)**	$ (126)
Total fair value consists of the following:		
Fair value, end of year—current asset portion	**$ 39**	$ 23
Fair value, end of year—current liability portion	**(114)**	(85)
Fair value, end of year—non-current asset portion	**28**	3
Fair value, end of year—non-current liability portion	**(46)**	(67)
Total fair value, end of year	**$ (93)**	$ (126)

Based on December 31, 2011 pricing, a $1.00 change in the price per barrel of liquids would change pre-tax unrealized risk management by $24 million and a $0.10 change in the price per mcf of natural gas would change pre-tax unrealized risk management by $2 million.

The following table reconciles the changes in the fair value of financial instruments including the realized components (settlements in cash) in the period:

Risk management asset (liability)	Year ended December 31 2011	2010
Balance, beginning of year	**$ (126)**	$ (151)
Realized loss—commodity contracts	**(63)**	20
Unrealized gain—commodity contracts	**71**	3
Realized loss—other	**1**	35
Unrealized gain (loss)—other	**24**	(33)
Total fair value, end of year	**$ (93)**	$ (126)

Penn West had the following financial instruments outstanding as at December 31, 2011. 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	60,000 bbls/d	Jan/12 – Dec/12	US$85.53 to $101.16/bbl	$ (103)
WTI Collars	5,000 bbls/d	Jan/13 – Dec/13	US$90.00 to $100.00/bbl	(1)
Natural gas				
AECO Forwards (1)	52,730 GJ/d	Jan/12 – Dec/12	$4.08/GJ	25
Electricity swaps				
Alberta Power Pool	45 MW	Jan/12 – Dec/12	$53.02/MWh	7
Alberta Power Pool	30 MW	Jan/12 – Dec/13	$54.60/MWh	10
Alberta Power Pool	20 MW	Jan/13 – Dec/13	$56.10/MWh	2
Alberta Power Pool	50 MW	Jan/14 – Dec/14	$58.50/MWh	1
Interest rate swaps	$650	Jan/12 – Jan/14	2.65%	(22)
Foreign exchange forwards on revenues				
12-month initial term	US$1,872	Jan/12 – Dec/12	1.022 CAD/USD	2
Foreign exchange forwards on senior notes				
3 to 15-year initial term	US$641	2014 – 2022	1.000 CAD/USD	20
Cross currency swaps				
10-year initial term	£57	2018	2.0075 CAD/GBP, 6.95%	(26)
10-year initial term	£20	2019	1.8051 CAD/GBP, 9.15%	(5)
10-year initial term	€10	2019	1.5870 CAD/EUR, 9.22%	(3)
Total				$ (93)

(1) The forward contracts total approximately 50,000 mcf per day with an average price of $4.30 per mcf.

A realized gain of $11 million (2010 – $14 million loss) on electricity contracts has been included in operating costs for 2011.

Subsequent to December 31, 2011, Penn West entered into additional crude oil collars on 30,000 barrels per day in 2013 between US$94.17 and US$109.23 per barrel.

Business 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. Hedging 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, 2011, the following foreign currency forward contracts were outstanding:

Nominal Amount	Settlement date	Exchange rate
Sell US$1,872	December 2012	1.02182 CAD/USD
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, 2011, Penn West had US dollar denominated debt with a face value of US$1.0 billion (2010—US$1.2 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, 2011, the maximum exposure to credit risk was $486 million (2010—$386 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, 2011, 19 percent of the Company's long-term debt instruments were exposed to changes in short-term interest rates (2010 – none).

As at December 31, 2011, a total of $2.0 billion (2010—$1.7 billion) of fixed interest rate debt instruments was outstanding with an average remaining term of 6.5 years (2010 – 7.2 years) and an average interest rate of 5.9 percent (2010 – 5.7 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 contractual obligations for non-derivative financial liabilities as at December 31, 2011:

	2012	2013	2014	2015	2016	Thereafter
Bank debt	**$ —**	$ —	$ —	$ 1,248	$ —	$ —
Senior unsecured notes	**—**	5	61	256	221	1,428
Accounts payable and accrued liabilities	**1,017**	—	—	—	—	—
Dividends payable	**127**	—	—	—	—	—
Share-based compensation accrual	**91**	9	—	—	—	—
Total	**$ 1,235**	$ 14	$ 61	$ 1,504	$ 221	$ 1,428

13. Income taxes

The provision for income taxes is as follows:

Deferred tax expense (recovery)	Year ended December 31 2011	2010
Changes in temporary differences	**$ 89**	$ (96)
Changes in tax rates and laws	**(316)**	(5)
Deferred tax recovery	**$ (227)**	$ (101)

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. In addition, Penn West included a net tax recovery of $45 million related to amendments and exchanges of share-based instruments under Penn West's equity-based compensation plans that occurred on January 1, 2011.

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 2011	2010
Income before taxes	**$ 411**	$ 1,009
Combined statutory tax rate	**26.9%**	39.0%
Computed income tax expense	**$ 111**	$ 394
Increase (decrease) resulting from:		
Effective rate change from SIFT temporary differences	**(304)**	—
Share-based compensation	**(20)**	43
Unrealized foreign exchange	**5**	(12)
Adjustment for previously enacted tax rates	**(5)**	(133)
Net income attributable to the trust	**—**	(246)
Tax basis retained on restructuring	**—**	(135)
Other	**(14)**	(12)
Deferred tax recovery	**$ (227)**	$ (101)

Other includes the impact of true-ups to tax filings, prior year assessments received in the current year and revisions of previous estimates.

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

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, 2010	Provision (Recovery) in Income	Provision (Recovery) in Equity	Provision (Recovery) in Business Combinations	Balance December 31, 2010
Deferred tax liabilities					
PP&E	$ 2,259	$ (4)	$ (4)	$ 28	$ 2,279
Deferred tax assets					
Risk management	(41)	9	—	—	(32)
Decommissioning liability	(144)	(20)	—	(1)	(165)
Non-capital losses	(544)	(86)	—	—	(630)
Net deferred tax liability	$ 1,530	$ (101)	$ (4)	$ 27	$ 1,452

	Balance January 1, 2011	Provision (Recovery) in Income	Provision (Recovery) in Equity	Provision (Recovery) in Business Combinations	**Balance December 31, 2011**
Deferred tax liabilities					
PP&E	$ 2,279	$ (84)	$ —	$ 61	**$ 2,256**
Deferred tax assets					
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**

At December 31, 2011, the net deferred tax liability consisted of a $16 million (2010 – $17 million) deferred tax asset and a $1,303 million (2010 – $1,469 million) deferred tax liability.

14. 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.

b) Issued

Shareholders' capital/ Unitholders' capital	Common Shares/Trust Units	Amount
Balance, December 31, 2009	421,638,737	$ 8,451
Issued on exercise of trust unit rights (1)	5,530,841	114
Issued to employee trust unit savings plan	2,025,699	42
Issued to distribution reinvestment plan	6,040,183	117
Issued to settle convertible debentures	922,580	18
Issued on trust unit offering (net of issue costs/tax)	23,524,209	428
Balance, December 31, 2010	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 restricted options (1)	**6,955,666**	**188**
Issued to dividend reinvestment plan	**4,734,815**	**92**
Balance, December 31, 2011	**471,372,730**	**$ 8,840**

(1) Upon exercise of options, the net benefit is recorded as a reduction of other reserves and an increase to shareholders' capital. Included in the exercised amount are 88,629 shares issued from Treasury as a result of individuals settling their restricted rights in common shares.

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	2011	2010
Balance, beginning of year	**$ —**	$ —
Set-up of Option Plan and CSRIP	**81**	—
Share-based compensation expense	**41**	—
Net benefit on options exercised (1)	**(27)**	—
Balance, end of year	**$ 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.

15. 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, options holders 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.

	Year ended December 31, 2011	
Options	**Number of Options**	**Weighted Average Exercise Price**
Outstanding, beginning of year	**—**	**$ —**
Granted	**8,531,536**	**25.84**
Forfeited	**(611,936)**	**27.34**
Outstanding, end of year	**7,919,600**	**$ 25.73**
Exercisable, end of year	**—**	**$ —**

	Options Outstanding			Options Exercisable	
Range of Grant Prices	Number Outstanding	Weighted Average Exercise Price	Weighted Remaining Contractual Life (years)	Number Exercisable	Weighted Average Exercise Price
$14.00—$18.99	747,700	$ 16.34	5.0	—	$ —
$19.00—$23.99	682,710	19.91	4.9	—	—
$24.00—$28.99	6,489,190	27.42	4.3	—	—
	7,919,600	$ 25.73	4.4	—	$ —

Common Share Rights Incentive Plan ("CSRIP")

Restricted Options and Restricted Rights

Prior to 2011, option 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, 2011 Number of Restricted Options	Weighted Average Exercise Price
Outstanding, beginning of year	—	$ —
Exchange of TURIP	27,586,712	23.84
Exercised (1)	(6,188,414)	23.84
Forfeited	(4,288,105)	23.84
Outstanding, end of year	17,110,193	$ 23.84
Exercisable, end of year	10,171,239	$ 23.84

(1) The weighted average share price on restricted options exercised in 2011 was $26.20 per share.

Restricted Rights	Year ended December 31, 2011 Number of Restricted Rights	Weighted Average Exercise Price
Outstanding, beginning of year	—	$ —
Exchange of TURIP	27,586,712	16.11
Exercised (1)	(9,061,792)	15.13
Forfeited	(1,414,727)	16.45
Outstanding, end of year (2)	17,110,193	$ 15.15
Exercisable, end of year	10,171,239	$ 15.10

(1) The weighted average share price on restricted rights exercised in 2011 was $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, 2011, $82 million was classified as a current liability (2010 – nil) included in accounts payable and accrued liabilities and $2 million was classified as a non-current liability (2010 – nil) included in other non-current liabilities.

	Restricted Rights Outstanding			Restricted Rights Exercisable	
Range of Adjusted Grant Prices	Number Outstanding	Weighted Average Exercise Price [1]	Weighted Remaining Contractual Life (years) [2]	Number Exercisable	Weighted Average Exercise Price [1]
$9.00—$14.99	5,725,143	$ 8.52	1.5	3,313,346	$ 8.50
$15.00—$20.99	4,530,003	17.57	2.2	1,680,788	16.83
$21.00—$26.99	6,129,291	18.79	1.2	4,471,299	18.32
$27.00—$32.99	335,906	21.80	0.6	335,906	21.80
$33.00—$38.99	389,850	21.36	1.0	369,900	21.28
	17,110,193	$ 15.15	1.5	10,171,239	$ 15.10

(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, 2011	
Share Rights	**Number of Share Rights**	**Weighted Average Exercise Price**
Outstanding, beginning of year	**—**	**$ —**
Exchange of TURIP	**3,778,766**	**22.46**
Exercised [1]	**(678,623)**	**15.15**
Forfeited	**(551,031)**	**22.21**
Outstanding, end of year [2]	**2,549,112**	**$ 23.13**
Exercisable, end of year	**2,325,725**	**$ 24.14**

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

Range of Grant Prices	CSRIP Outstanding Number Outstanding	Weighted Average Exercise Price [1]	Weighted Remaining Contractual Life (years) [2]	CSRIP Exercisable Number Exercisable	Weighted Average Exercise Price [1]
$9.00—$15.99	230,622	$ 8.23	1.5	112,181	$ 8.46
$16.00—$22.99	159,458	17.10	2.1	57,712	16.04
$23.00—$29.99	420,325	21.67	0.6	420,325	21.67
$30.00—$36.99	916,357	25.75	0.6	913,157	25.76
$37.00—$44.32	822,350	26.29	0.6	822,350	26.29
	2,549,112	$ 23.13	0.8	2,325,725	$ 24.14

(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.

	Year ended December 31			
	2011		2010	
TURIP	**Number of Unit Rights**	**Weighted Average Exercise Price**	Number of Unit Rights	Weighted Average Exercise Price
Outstanding, beginning of year	**31,365,478**	**$ 16.88**	31,816,158	$ 17.65
Granted	**—**	**—**	7,689,930	19.90
Exercised	**—**	**—**	(5,530,841)	16.38
Forfeited	**—**	**—**	(2,609,769)	18.22
Exchange for Restricted Options/ Rights	**(27,586,712)**	**16.11**	—	—
Exchange for Share Rights	**(3,778,766)**	**22.46**	—	—
Outstanding, end of year [1]	**—**	**$ —**	31,365,478	$ 16.88
Exercisable, end of year	**—**	**$ —**	13,895,742	$ 17.52

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

Prior to the conversion to a corporation, the fair value of the TURIP obligation was classified as a current liability of $171 million included in accounts payable and accrued liabilities and a non-current liability of $25 million was included in other non-current liabilities at December 31, 2010.

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 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 during the period preceding the vesting date.

	Year ended December 31	
LTRIP awards (number of shares equivalent)	**2011**	2010
Outstanding, beginning of year	**700,669**	—
Granted	**1,076,556**	740,985
Vested and paid	**(224,050)**	—
Forfeited	**(141,499)**	(40,316)
Outstanding, end of year	**1,411,676**	700,669

At December 31, 2011, LTRIP obligations of $9 million were classified as a current liability (2010—$4 million) included in accounts payable and accrued liabilities and $7 million were classified as a non-current liability (2010—$4 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	
	2011	2010
Options	**$ 18**	$ —
Restricted Options	**22**	—
Restricted Rights	**(29)**	—
Share Rights	**1**	—
LTRIP	**14**	8
TURIP	**—**	151
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	**$ 84**	$ 159

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

On January 1, 2011, the TURIP liability was removed and a liability was recorded to reflect the Restricted Rights. Additionally, the fair values to reflect the initiation 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 in 2011 under the Option Plan with the following fair value per option and weighted average assumptions:

	Year ended December 31	
	2011 (1)	2010 (2)
Average fair value of options granted (per share)	**$ 6.26**	$ 5.08
Expected life of restricted options (years)	**4.0**	3.0
Expected volatility (average)	**29.9%**	32.2%
Risk-free rate of return (average)	**1.9%**	2.3%
Dividend yield	**5.3%**	6.8%

(1) In 2011, assumptions relate to the Option Plan.
(2) In 2010, assumptions relate to the TURIP. Trust unit rights fair value was determined using a Binomial Lattice option-pricing model.

The expected volatility of the trust unit rights was based on the historical unit price volatility of Penn West. The expected life of the trust unit rights was based on expected exercise patterns and the forfeiture rate was based on historical employee forfeiture patterns.

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.

DSU plan

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, 2011, 14,390 DSUs were outstanding (2010 – nil).

16. Dividends

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

In 2011, Penn West paid dividends of $420 million or $0.90 per share (2010 – distributions of $708 million or $1.62 per unit).

On January 13, 2012, Penn West paid its fourth quarter dividend of $0.27 per share totalling $127 million. On February 15, 2012, Penn West declared its first quarter 2012 dividend of $0.27 per share to be paid on April 13, 2012 to shareholders of record on March 30, 2012.

17. 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.

(millions)	Year ended December 31 **2011**	2010
Net income	**$ 638**	$ 1,110
Interest on potentially dilutive convertible debentures	**—**	10
Diluted net income	**$ 638**	$ 1,120

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

	Year ended December 31 **2011**	2010
Basic	**467,186,047**	441,813,114
Diluted Impact – Options/ Trust Unit Rights	**260,241**	5,390,821
Diluted Impact – Convertible debentures	**—**	4,441,589
Diluted	**467,446,288**	451,645,524

For 2011, 26.2 million shares (2010 – 11.5 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. In 2010, 0.3 million shares that would be issued on the conversion of the convertible debentures were excluded as they were considered anti-dilutive.

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

	Year ended December 31 **2011**	2010
Accounts receivable	**$ (95)**	$ (15)
Other current assets	**(17)**	14
Deferred funding obligation	**(25)**	15
Accounts payable and accrued liabilities	**201**	226
	$ 64	$ 240
Operating activities	**$ (49)**	$ 85
Investing activities	**113**	155
	$ 64	$ 240
Interest paid	**$ 189**	$ 147
Income taxes recovered	**$ —**	$ (1)

19. 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.

Sifton Energy Inc. (“Sifton”) Acquisition

On December 22, 2010, Penn West closed the acquisition of Sifton, a private oil and gas exploration company. The total acquisition cost was approximately $108 million, which included the assumption of approximately $23 million of debt and working capital.

Penn West accounted for the Spartan and Sifton acquisitions as business combinations. The consolidated financial statements of Penn West include the results of operations of Spartan from the closing date of June 1, 2011 and Sifton from the closing date of December 22, 2010. If the Spartan acquisition had occurred on January 1, 2011, and the Sifton acquisition had occurred on January 1, 2010, Penn West would have realized the following pro forma results for the years ended:

	Year ended December 31	
	2011	2010
Revenue ($CAD millions)	**$ 3,029**	$ 2,527
Net income ($CAD millions)	**$ 641**	$ 1,105

20. 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 organic growth and yield.

Shareholders’ equity, long-term debt and convertible debentures 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 funds flow 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, 2011, the Company was in compliance with all of its financial covenants.

(millions, except ratio amounts)	Year ended December 31 2011	2010 [1,8,9,10,11]
Components of capital		
Shareholders' equity	**$ 9,067**	$ 8,560
Long-term debt	**3,219**	2,496
Convertible debentures	**$ —**	$ 255
Ratios		
Senior debt to EBITDA [2]	**1.9**	1.8
Total debt to EBITDA [3]	**1.9**	1.9
Senior debt to capitalization [4]	**26%**	23%
Total debt to capitalization [5]	**26%**	23%
Total debt to capitalization [5]	**26%**	25%
Priority debt to consolidated tangible assets [6]	**—**	—
EBITDA [7]	**$ 1,736**	$ 1,359
Credit facility debt and senior notes	**$ 3,219**	$ 2,496
Letters of credit	**3**	2
Total senior debt	**3,222**	2,498
Convertible debentures	**—**	26
Total debt	**3,222**	2,524
Convertible debentures	**—**	229
Total debt	**3,222**	2,753
Total shareholders' equity	**9,067**	—
Total unitholders' equity	**—**	8,560
Total capitalization	**$ 12,289**	$ 11,313

(1) 2010 ratios have been disclosed under previous GAAP, as filed in the prior year under the terms of our bank facility and senior unsecured notes.
(2) Less than 3:1 and not to exceed 3.5:1 in the event of a material acquisition.
(3) Less than 4:1.
(4) Not to exceed 50 percent except in the event of a material acquisition when the ratio is not to exceed 55 percent.
(5) Not to exceed 55 percent except in the event of a material acquisition when the ratio is not to exceed 60 percent.
(6) Priority debt not to exceed 15% of consolidated tangible assets.
(7) EBITDA is calculated in accordance with Penn West's lending agreements wherein unrealized risk management and impairment provisions are excluded.
(8) Convertible debentures not meeting the requirements for equity classification under lending agreements.
(9) Convertible debentures not meeting the requirements for equity classification under the 2007 Notes.
(10) Total debt as defined in the 2008 Notes, UK Notes, 2009 Notes, 2010 Q1 Notes, 2010 Q4 Notes and the syndicated bank facility agreements, which includes convertible debentures that do not meet the requirement for equity classification in these agreements.
(11) Total debt as defined in the 2007 Notes agreement, which includes convertible debentures that do not meet the requirements for equity classification in this agreement.

21. Commitments and contingencies

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

(millions)	**2012**	2013	2014	2015	2016	Thereafter
Long-term debt	**$ —**	$ 5	$ 61	$ 1,504	$ 221	$ 1,428
Transportation	**23**	19	12	8	3	—
Transportation ($US)	**4**	4	37	37	33	231
Power infrastructure	**32**	15	15	15	15	14
Drilling rigs	**26**	26	22	16	10	2
Purchase obligations (1)	**13**	13	11	10	2	5
Interest obligations	**161**	161	158	127	93	216
Office lease (2)	**68**	66	60	60	59	479
Decommissioning liability (3)	**$ 70**	$ 67	$ 64	$ 61	$ 58	$ 287

(1) These amounts represent estimated commitments of $40 million for CO_2 purchases and $14 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 $434 million. For 2011, lease cost, net of recoveries totalled $38 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 26, 2015. If Penn West is not successful in renewing or replacing the facility, it could enter other loans including term bank loans or be required to repay all amounts then outstanding on the facility. In addition, Penn West has an aggregate of $2.0 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 usage.
- Power infrastructure commitments pertain to electricity contracts.
- Drilling rigs are contracts held with service companies ensuring Penn West has the 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 interests at Penn West's Weyburn CO2 miscible flood property in S.E. Saskatchewan.
- Interest obligations are the estimated future interest payments related to Penn West's debt instruments that are currently outstanding.
- 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.

22. Related-party transactions

Operating entities

The 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.

Related party transactions

During 2011, Penn West incurred $1 million (2010 – $2 million) of legal fees in the normal course of business from a law firm of which a partner is also a director of Penn West.

Compensation of key management personnel

Key management personnel include the President and Chief Executive Officer, Executive Vice President and Chief Operating Officer, the Executive/ Senior Vice-Presidents and the Board of Directors. The Human Resources & Compensation Committee makes recommendations regarding and the Board of Directors determines 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	
	2011	2010
Salary and employee benefits	**$ 9**	$ 7
Share-based payments [1]	**11**	25
	$ 20	$ 32

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

23. Supplemental Items

In Penn West's financial statements, items are primarily disclosed by nature except for employee compensation costs which are included in both operating and general and administrative expenses. For 2011, employee compensation costs of $127 million (2010—$124 million) were included in operating costs and $129 million (2010—$112 million) were included in general and administrative expenses.

24. Transition to IFRS

Penn West's accounting policies under IFRS, as described in Note 3, differ from those followed under previous GAAP. These accounting policies have been applied for the year ended December 31, 2011 as well as the comparative information on the January 1, 2010 (the "transition date") opening balance sheet and the comparative information for the year ended December 31, 2010.

The adjustments arising from the application of IFRS to balance sheet account balances on January 1, 2010, the effective date of transition, and on transactions prior to that date were recognized as an adjustment to opening retained earnings or, as appropriate, another category of equity or an adjustment to another balance sheet account.

On the transition date, Penn West elected to apply IFRS 1, which included the following:

i) Business combinations

For business combinations completed before the transition date, Penn West elected not to adopt IFRS 3 "Business Combinations" retrospectively. Accordingly, the fair value of assets and liabilities on business combinations prior to the transition date remain at the amounts determined under previous GAAP.

Goodwill was required to be valued at its carrying amount on the transition date and subject to a goodwill impairment test on that date, regardless of whether there was an indication of impairment. There was no impairments calculated from the impairment test on the transition date.

ii) PP&E

Penn West recognized PP&E in the opening IFRS balance sheet applying the amendment to IFRS 1 "Additional exemptions for first-time adopters". The recorded amount of oil and gas assets, at the date of transition, was deemed to be equal to the historical cost of oil and gas assets under previous GAAP, except for Corporate Assets and E&E assets.

The cost of oil and gas assets was allocated between CGUs based on total proved plus probable reserve values and the fair value of certain assets on January 1, 2010. Additionally, oil and gas assets were tested for impairment on the transition date, a requirement when applying the “Deemed Cost” exemption under IFRS 1, and no impairments were indicated. The cost of corporate assets was determined in a similar manner as oil and gas assets.

iii) Share based payment transactions

Penn West granted equity instruments prior to the transition date that fall within the scope of IFRS 2 “Share based payments”. Under IFRS 1, Penn West had the option to apply IFRS 2 to only non-vested options on the transition date, however, did not apply this exemption.

iv) Decommissioning liabilities

Application of the “Deemed Cost” exemption on January 1, 2010 required that changes to decommissioning liabilities on the transition date be recorded to retained earnings. On January 1, 2010, Penn West recorded certain reclamation liabilities related primarily to pipeline ownership, as they met the definition of a constructive obligation under IAS 37 “Provisions, Contingent Liabilities and Contingent Assets”. Under previous GAAP, constructive obligations were not recognized.

Reconciliation of Equity reported under previous GAAP
to Equity reported under IFRS on the Transition Date (January 1, 2010)

(CAD millions)	Notes	January 1, 2010 Previous GAAP	Transition Adjustments	IFRS
Assets				
Current				
Accounts receivable		$ 371	$ —	$ 371
Other		101	—	101
Deferred tax asset	A	37	(37)	—
Risk management	B	—	29	29
		509	(8)	501
Non-current				
Exploration and evaluation assets	C	—	132	132
Property, plant and equipment	C,D	11,347	(173)	11,174
Goodwill		2,020	—	2,020
Risk management	B	—	10	10
		13,367	(31)	13,336
Total assets		$ 13,876	$ (39)	$ 13,837
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	E	$ 515	$ 53	$ 568
Distribution payable		63	—	63
Convertible debentures		18	—	18
Risk management	B	130	29	159
		726	82	808
Non-current liabilities				
Long-term debt		3,219	—	3,219
Convertible debentures		255	—	255
Decommissioning liability	F	568	(6)	562
Risk management	B	21	10	31
Deferred tax liability	A	1,169	361	1,530
Other non-current liabilities	E	—	15	15
		5,958	462	6,420
Unitholders' equity				
Unitholders' capital	E	8,451	—	8,451
Contributed surplus	E	123	(123)	—
Deficit	A, C, D, E, F	(656)	(378)	(1,034)
		7,918	(501)	7,417
Total liabilities and unitholders' equity		$ 13,876	$ (39)	$ 13,837

Reconciliation of Equity reported under previous GAAP to Equity reported under IFRS as at December 31, 2010

(CAD millions)	Notes	December 31, 2010 Previous GAAP	Effect of Transition	IFRS
Assets				
Current assets				
Accounts receivable		$ 386	$ —	$ 386
Other		87	—	87
Deferred income tax	A	17	(17)	—
Risk management	B	—	23	23
		490	6	496
Non-current assets				
Deferred funding asset		678	—	678
Exploration and evaluation assets	C	—	128	128
Property, plant and equipment	C, D, F	10,180	1,038	11,218
Goodwill		2,020	—	2,020
Risk management	B	—	3	3
		12,878	1,169	14,047
Total assets		$13,368	$ 1,175	$14,543
Liabilities and Unitholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	E	$ 743	$ 167	$ 910
Distributions payable		41	—	41
Convertible debentures	G	—	255	255
Risk management	B	62	23	85
		846	445	1,291
Non-current liabilities				
Long-term debt		2,496	—	2,496
Convertible debentures	G	255	(255)	—
Decommissioning liability	F	653	(5)	648
Risk management	B	64	3	67
Deferred tax liability	A	855	597	1,452
Other non-current liabilities	E	—	29	29
		5,169	814	5,983
Unitholders' equity				
Unitholders' capital	H	9,177	(7)	9,170
Other reserves	E	138	(138)	—
Retained earnings (deficit)	H	(1,116)	506	(610)
		8,199	361	8,560
Total liabilities and unitholders' equity		$13,368	$ 1,175	$14,543

Reconciliation of Net and Comprehensive Income reported under previous GAAP to IFRS for the year ended December 31, 2010

(CAD millions, except per share amounts)	Notes	Year ended December 31, 2010 Previous GAAP	Effect of Transition	IFRS
Oil and natural gas sales		$ 3,054	$ —	$ 3,054
Royalties		(545)	—	(545)
		2,509	—	2,509
Risk management gain (loss)				
Realized		(20)	—	(20)
Unrealized		23	—	23
		2,512	—	2,512
Expenses				
Operating	E	959	(15)	944
Transportation		33	—	33
General and administrative	E	181	(36)	145
Unit-based compensation	E	—	159	159
Depletion, depreciation and accretion	D	1,338	(1,338)	—
Depletion and depreciation	D	—	1,169	1,169
Gain on dispositions	D	—	(1,082)	(1,082)
Exploration and evaluation	C	—	1	1
Unrealized risk management gain		(2)	—	(2)
Unrealized foreign exchange gain		(82)	—	(82)
Transaction costs		4	(4)	—
Financing		174	—	174
Accretion	D, F	—	44	44
		2,605	(1,102)	1,503
Income (loss) before taxes		**(93)**	**1,102**	**1,009**
Deferred tax expense (recovery)	A	(319)	218	(101)
Net and comprehensive income		**$ 226**	**$ 884**	**$ 1,110**
Net income per unit				
Basic		$ 0.51	$ 2.00	$ 2.51
Diluted	H	$ 0.50	$ 1.98	$ 2.48

Notes to reconciliation

A. Deferred income taxes

i) Classification

Under previous GAAP, Penn West was required to disclose the current and long-term components of deferred income taxes separately. Under IFRS, deferred income taxes are disclosed as non-current.

ii) Measurement

Under previous GAAP, income tax assets and liabilities of trust entities were measured at the enacted Specified Investment Flow-Through tax rate of approximately 25 percent. Under IFRS, Penn West was required to measure trust tax assets and liabilities at a rate of approximately 39 percent, representing the tax rate applicable to undistributed profits of a trust entity in the Province of Alberta. On the transition date, a charge to retained earnings of approximately $410 million was recorded. Penn West also recorded approximately $12 million of deferred tax recoveries related to PP&E adjustments on the transition date.

During 2010, the adjustment of the deferred tax liability for the recognition of gains on asset dispositions under IFRS and the declaration of distributions resulted in a $101 million deferred tax recovery through income.

B. Risk management classification

Under previous GAAP, Penn West grouped current and non-current risk management balances related to financial instruments. Under IFRS, Penn West reclassified risk management between current and non-current.

C. Exploration and evaluation assets

Under previous GAAP, all oil and gas assets, whether development or exploratory in nature, were included in PP&E. Under IFRS, certain E&E costs are recorded separately from PP&E as E&E assets. On the transition date, Penn West reclassified $132 million from PP&E to E&E assets.

Also, on the transition date, Penn West identified approximately $44 million of lands for which the Company has no current plans to develop or explore. This amount was charged to retained earnings as required under IFRS.

During the 2010, Penn West spent $58 million on E&E assets, sold $61 million of E&E assets in acquisition and divestiture activities and recorded a $1 million E&E expense related to land expiries.

D. Property, plant and equipment

i) Componentization – Plant Turnaround Costs

Under previous GAAP, Penn West did not capitalize costs associated with turnarounds. Under IFRS, costs associated with major inspections of property, plant or equipment are capitalized. On the transition date, Penn West capitalized $10 million of turnaround costs to PP&E and $7 million to accumulated depletion and depreciation as an opening retained earnings adjustment. Significant turnaround costs will be treated as a separate component under IFRS and depreciated on a straight-line basis. There have been no significant turnarounds requiring capitalization subsequent to the transition date.

ii) Depletion, depreciation and accretion

During 2010, Penn West recorded $1,169 million of depletion and depreciation under IFRS compared to $1,293 million under previous GAAP.

Under previous GAAP, PP&E was generally depleted based on aggregations at the country level using the full cost method of accounting for oil and natural gas activities and the unit of production method based on proved reserves. Depletion of resource properties and facilities will generally continue to be calculated using the unit-of-production method under IFRS; however, Penn West has elected to deplete resource properties using proved plus probable reserves. Depreciation of other assets is calculated on a straight-line basis over their estimated useful lives. Depletion and depreciation is calculated at the component level.

Under previous GAAP, depletion, depreciation and accretion was disclosed in aggregate in the consolidated statement of income. Under IFRS, accretion has been disclosed on a separate line.

iii) Impairment

Under IFRS, impairment testing is performed at a lower level of asset aggregation than under previous GAAP. During the second quarter of 2010, Penn West recorded an $80 million pre-tax impairment related to certain properties in Central Alberta to reflect declining economic factors which resulted in lower estimated future cash flows. The charge was included in depletion and depreciation.

iv) Gains and losses on dispositions

Under previous GAAP, proceeds on dispositions were applied to PP&E unless the disposition changed the rate of depletion and depreciation by more than 20 percent in which case gains and losses were recognized. Under IFRS, gains and losses are calculated on significant dispositions and are recognized in income. During 2010, Penn West completed a number of property dispositions of which the two most significant dispositions were to form the Peace River Oil Partnership and the Cordova Joint Venture. These dispositions resulted in 2010 pre-tax gains of $749 million and $368 million, respectively.

v) PP&E continuity

Changes in PP&E from previous GAAP as at January 1, 2010 and the year ending December 31, 2010 were as follows:

	January 1, 2010	December 31, 2010
PP&E balance, previous GAAP	$ 11,347	$ 10,180
Reverse previous GAAP amounts:		
Depletion and depreciation	—	1,293
ARO revisions	—	(89)
Record IFRS adjustments:		
Set-up of E&E assets	(176)	(176)
Set-up of turnaround component	3	3
E&E previously recorded as PP&E	—	(58)
Depletion and depreciation	—	(1,169)
Gain on dispositions	—	1,143
ARO revisions	—	91
PP&E balance, IFRS	$ 11,174	$ 11,218

E. Unit-based compensation

Under previous GAAP, the fair values of trust unit rights under the TURIP were amortized to income on a straight-line basis and classified as equity instruments. Under IFRS in 2010, trust unit rights were classified as a liability and were expensed as the service of the employee was provided.

On the transition date, Penn West reversed contributed surplus (other reserves) of $123 million to remove the amount recorded as equity under previous GAAP and recorded a unit rights liability based on updated fair values per trust unit right and the service performed to that date. This resulted in the recognition of a $68 million unit rights liability on the transition date of which $53 million was recorded in accounts payable and accrued liabilities and $15 million was recorded in other non-current liabilities.

Under previous GAAP, Penn West included a portion of unit-based compensation in operating expense and the balance in general and administrative expense. Under IFRS, unit-based compensation is disclosed on a separate line on the consolidated statement of income. Penn West reclassified $4 million from operating costs and $4 million from general and administrative expenditures into unit-based compensation expense for 2010. Additionally Penn West reclassified $4 million from accounts payable and accrued liabilities into other non-current liabilities as this amount was non-current at December 31, 2010.

Under IFRS, as trust unit rights were treated as a liability, Penn West was required to revalue unit-based compensation at each reporting date. In 2010, an expense of $151 million was recorded resulting in a unit rights liability of $196 million at December 31, 2010 of which $171 million was included in accounts payable and accrued liabilities and $25 million was included in other non-current liabilities.

Due to the revaluation of trust unit rights at each reporting date under IFRS, the amount recorded as an increase to unitholders' equity on exercises changed from previous GAAP. Upon the exercise of rights, for 2010 Penn West recorded $23 million in unitholders' equity compared to $32 million under previous GAAP.

F. Decommissioning liability

Under previous GAAP, a decommissioning liability existed if there was a legal requirement to abandon and reclaim an asset. Under IFRS, in addition to the legal requirement, constructive obligations to abandon and reclaim an asset are included in the provision. Also, under IFRS, the decommissioning liability is calculated at a more detailed level than under previous GAAP, which results in minor differences in the present value calculation. On the transition date, Penn West recorded a reduction in the decommissioning liability of approximately $6 million with a corresponding offset to opening deficit.

During 2010, Penn West had $91 million of additions and changes in estimates which increased the liability and accretion charges totalling $44 million under IFRS. These amounts were $89 million and $45 million, respectively, under previous GAAP.

G. Convertible debentures

Under previous GAAP, convertible debentures that expire within a year were disclosed as a long-term liability as Penn West, at its discretion, had the option of settling the debentures in cash or equity. Under IFRS, regardless of the method of settlement, instruments expiring within one year are classified as current liabilities.

H. Unitholders' Equity

Changes to deficit from previous GAAP were as follows:

	January 1, 2010	December 31, 2010
Deficit, previous GAAP	$ (656)	$ (1,116)
Reverse previous GAAP amounts:		
Depletion, depreciation and accretion	—	1,338
Unit-based compensation	—	47
Future income tax	—	(319)
Record IFRS adjustments:		
Set-up of turnaround component	3	3
Set-up of decommissioning liability	6	6
Set-up of unit rights liability	55	55
Deferred tax	(398)	(297)
E&E expense	(44)	(45)
Depletion and depreciation	—	(1,169)
Accretion	—	(44)
Unit-based compensation expense	—	(151)
Gain on dispositions	—	1,082
Deficit, IFRS	$ (1,034)	$ (610)

Changes to unitholders' capital from previous GAAP at the comparative dates were as follows:

	January 1, 2010	December 31, 2010
Unitholders' capital, previous GAAP	$ 8,451	$ 9,177
Reverse previous GAAP amounts:		
Exercises of TURIP	—	(32)
Tax-effect on trust unit issue costs	—	(2)
Record IFRS adjustments:		
Exercises of TURIP	—	23
Tax-effect on trust unit issue costs	—	4
Unitholders' capital, IFRS	$ 8,451	$ 9,170

Contributed surplus (other reserves) of $123 million was eliminated and charged through retained earnings on January 1, 2010 to record trust unit rights as a liability under IFRS.

I. Earnings per unit

Under previous GAAP in 2010, the number of units used in the year-to-date earnings per unit calculation was based on the average of the number of units outstanding in each of the interim periods. Under IFRS, the year-to-date calculation is completed independent of the quarterly calculations.

For the year ended 2010, the diluted number of units outstanding under IFRS was 451.6 million compared to 447.6 million under previous GAAP.

J. Cash Flow statement

There were no changes to cash flow from operations, financing or investing as a result of adopting IFRS.

SUPPLEMENTARY OIL AND GAS INFORMATION—(UNAUDITED)

The following disclosures in this section provide oil and gas information in accordance with the U.S. standard, "Extractive Industries — Oil and Gas". In the first quarter of 2011, Penn West completed its change to International Financial Reporting Standards ("IFRS"). Penn West's 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.

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, 2011, 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, 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

YEAR ENDED DECEMBER 31, 2010
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, 2009	228	49	693	16	408
Extensions & Discoveries	13	—	38	1	20
Improved Recovery	8	1	10	—	12
Technical Revisions	11	3	82	3	30
Acquisitions	7	3	19	1	14
Dispositions	(15)	(2)	(35)	—	(24)
Production	(21)	(6)	(122)	(3)	(51)
Change for the year	4	(2)	(8)	1	2
December 31, 2010	232	47	685	17	410
Developed	186	47	617	15	351
Undeveloped	46	1	69	2	59
Total [2]	232	47	685	17	410

(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)	2011	2010
Proved oil and gas properties	$ 20,235	$ 18,554
Unproved oil and gas properties	418	128
Total capitalized costs	20,653	18,682
Accumulated depletion and depreciation	(8,342)	(7,336)
Net capitalized costs	$ 12,311	$ 11,346

COSTS INCURRED

For the years ended December 31, ($CAD millions)	2011	2010
Property acquisition (disposition) costs [1]		
Proved oil and gas properties	$ (266)	$ (1,306)
Unproved oil and gas properties	181	102
Exploration costs [2]	330	68
Development costs [3]	1,417	1,023
Joint venture, carried capital	(107)	(17)
Capital expenditures	1,555	(130)
Corporate acquisitions	286	139
Total expenditures	$ 1,841	$ 9

(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.

RESULTS OF OPERATIONS OF PRODUCING ACTIVITIES

For the years ended December 31, ($CAD millions)	2011	2010
Oil and gas sales, net of royalties and commodity contracts	$ 2,951	$ 2,512
Lease operating costs and capital taxes	(1,036)	(944)
Transportation costs	(29)	(33)
Depletion, depreciation and accretion	(1,203)	(1,213)
Income taxes [1]	—	—
Results of operations	$ 683	$ 322

(1) Penn West is currently not cash taxable.

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 applied against annual future production from 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 the average of the first day prices of each month for the prior calendar 12-month period. Future income taxes are calculated by applying statutory income tax rates. 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 appropriately reflect future interest rates.

($CAD millions)	2011	2010
Future cash inflows	$ 30,815	$ 24,117
Future production costs	(12,287)	(11,765)
Future development costs	(2,350)	(1,306)
Undiscounted pre-tax cash flows	16,178	11,046
Future income taxes [1]	(2,463)	(583)
Future net cash flows	13,715	10,463
Less 10% annual discount factor	(5,080)	(4,382)
Standardized measure of discounted future net cash flows	$ 8,635	$ 6,081

(1) Penn West is currently not cash taxable.

($CAD millions)	2011	2010
Estimated future net revenue at beginning of year	$ 6,081	$ 4,397
Oil and gas sales during period net of production costs and royalties (1)	(1,878)	(1,512)
Changes due to prices and royalties related to forecast production (2)	2,068	643
Development costs during the period (3)	1,821	1,187
Changes in forecast development costs (4)	(1,774)	(1,108)
Changes resulting from extensions and improved recovery (5)	1,256	485
Changes resulting from acquisitions of reserves (5)	115	208
Changes resulting from dispositions of reserves (5)	(164)	(233)
Discount factor (6)	608	440
Net change in income tax (7)	(917)	(115)
Changes resulting from technical reserves revision	118	459
All other changes (8)	1,300	1,231
Estimated future net revenue at end of year	$ 8,635	$ 6,081

(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. At December 31, 2010, Penn West operated as an income trust and converted to a corporation on January 1, 2011.
(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 16, 2012

/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 16, 2012

/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, 2011, 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 16, 2012

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, 2011, 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 16, 2012

Exhibit 99.9

Consent of Independent Registered Public Accounting Firm

The Board of Directors of Penn West Petroleum Ltd.

We consent to the use of our audit report dated March 15, 2012, on the financial statements of Penn West Petroleum Ltd., which comprise the consolidated balance sheets as at December 31, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of income, cash flows and changes in shareholders' equity for the years ended December 31, 2011 and 2010, and notes, comprising a summary of significant accounting policies and other explanatory information, and our audit report dated March 15, 2012 on the effectiveness of internal control over financial reporting which are included herein.

We also consent to incorporation by reference of the above mentioned audit reports in Penn West Petroleum Ltd.'s Registration Statement (No. 333-171675) on Form F-3.

/s/ KPMG LLP
Chartered Accountants

Calgary, Canada
March 15, 2012

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. Stilling, 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 February 8, 2012 and effective as of December 31, 2011, 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, 2011 and (ii) our report dated February 6, 2012 and effective as of December 31, 2011 consolidating the independent evaluations and audit of Penn West's oil and natural gas properties as at December 31, 2011 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, 2011; 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.

"Originally Signed by"

Bryan M. Joa, P. Eng.
Vice President

Dated: March 15, 2012
Calgary, Alberta
CANADA

Exhibit 99.11



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

*Directors

Ref.: 1772

March 15, 2012

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 6, 2012 and effective as of December 31, 2011, 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, 2011 (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, 2011; 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

Original Signed by Gary R. Finnis, P.Eng.

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

Worldwide Petroleum Consultants
900, 140 Fourth Avenue SW Calgary AB T2P 3N3 Canada | Phone: 1-403-294-5500 | Fax: 1-403-294-5590 | Toll-Free: 1-877-777-6135
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