PERPETUAL ENERGY INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc's ("Perpetual" or the "Corporation") operating and financial results for the three and nine months ended September 30, 2011 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's condensed interim consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2011 and 2010, which were prepared in accordance with International Accounting Standard 34 – Interim Financial Reporting, as well as the audited consolidated financial statements and accompanying notes and MD&A for the years ended December 31, 2010 and 2009. The Corporation's financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS"), which replaced previously generally accepted accounting principles in Canada ("GAAP") on January 1, 2011, with a transition date of January 1, 2010. Readers are referred to the Transition to IFRS section of this MD&A. Readers are referred to the advisories regarding forecasts, assumptions and other forward-looking information contained in the "Forward-Looking Information" section of this MD&A. The date of this MD&A is November 7, 2011.

Mcf equivalent ("Mcfe") may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), an Mcfe conversion ratio for oil of 1 bbl: 6 Mcf has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. For natural gas, gigajoules ("GJ") are converted to Mcf at a conversion ratio of 1.0546 GJ: 1 Mcf.

CORPORATE

On June 30, 2010, Perpetual announced that the Corporation had completed the previously announced plan of arrangement (the "Arrangement") involving Perpetual, Paramount Energy Trust (the "Trust") and Paramount Energy Operating Corp. pursuant to which the Trust converted into the Corporation. Unitholders of the Trust voted in favor of the Arrangement at the Annual General and Special Meeting of Trust Unitholders held on June 17, 2010. Former Unitholders of the Trust received common shares of Perpetual in consideration for the cancellation of their Trust Units of the Trust on a one-for-one basis. In addition, as part of the Arrangement, the Trust was dissolved and the Corporation assumed all of the existing liabilities of the Trust, including the Trust's outstanding convertible debentures which are now convertible debentures of the Corporation.

References to "common shares" and "Shareholders" are references to the securities of the Corporation and the holders thereof following the conversion date, and references to "dividends" are references to dividends paid by Perpetual following the conversion date, to distributions paid by the Trust prior to the conversion date, or both as the context may require.

SIGNIFICANT ACCOUNTING POLICIES AND NON-GAAP MEASURES

Accounting for property, plant and equipment

The Corporation charges exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties as well as the cost of expired leases to earnings or loss in the period incurred. This accounting policy differs relative to many entities in the Canadian oil and gas industry that capitalize some of these costs. To make reported funds flow in this MD&A more comparable to industry practice the Corporation reclassifies geological and geophysical costs and dry hole costs from operating to investing activities in the funds flow reconciliation.

Funds flow

Management uses cash flow from operations before changes in non-cash working capital, gas over bitumen royalty adjustments not yet received, trust unit distributions, settlement of decommissioning obligations and certain exploration costs described above ("funds flow"), funds flow per common share, annualized funds flow and trailing four quarters funds flow to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by GAAP and therefore it may not be comparable to the calculation of similar measures for other entities. Funds flow as presented is not intended to represent operating profits for the period nor should it be viewed as an alternative to cash flow provided by operating activities, net earnings or loss or other measures of financial performance calculated in accordance with GAAP.

Funds flow is reconciled to its closest GAAP measure, cash flow provided by operating activities, as follows:

Funds flow GAAP reconciliation

($ thousands except per common share amounts)	Three months ended September 30 2011	Three months ended September 30 2010	Nine months ended September 30 2011	Nine months ended September 30 2010
Cash flow provided by operating activities	**17,773**	43,388	**50,678**	119,672
Exploration and evaluation costs [1]	**827**	381	**2,957**	2,547
Expenditures on asset retirement obligations	**2,596**	667	**4,381**	3,679
Gas over bitumen royalty obligation adjustments not yet received	**2,480**	1,548	**845**	1,964
Distributions expensed through earnings (loss)	**-**	-	**-**	40,549
Changes in non-cash operating working capital	**(4,358)**	92	**2,232**	(1,450)
Funds flow	**19,318**	46,076	**61,093**	166,961
Funds flow per common share	**0.13**	0.32	**0.41**	1.19

(1) Certain exploration and evaluation costs are added back to funds flow in order to be more comparable to other corporations that capitalize some of these costs. Exploration costs that are added back to funds flow include seismic expenditures and dry hole costs and are considered by Perpetual to be more closely related to investing activities than operating activities.

Additional significant and new accounting policies and non-GAAP measures are discussed elsewhere in this MD&A.

OPERATIONS

Capital expenditures

Capital expenditures ($ thousands)	Three months ended September 30 2011	Three months ended September 30 2010	Nine months ended September 30 2011	Nine months ended September 30 2010
Exploration and development [1]	**38,562**	27,563	**100,945**	77,191
Gas storage	**2,537**	23,104	**10,880**	46,574
Acquisitions	**5,053**	1,072	**6,855**	139,241
Dispositions [2]	**(7,049)**	(16,951)	**(38,062)**	(54,335)
Other	**289**	101	**491**	375
Total capital expenditures	**39,392**	34,889	**81,109**	209,046

(1) Exploration and development expenditures for the three and nine months ended September 30, 2011 include approximately $0.8 million and $3.0 million in exploration costs (three and nine months ended September 30, 2010 - $0.4 million and $2.5 million, respectively) which have been expensed directly on the Corporation's statement of earnings (loss). Exploration costs including seismic expenditures and dry hole costs are considered by Perpetual to be more closely related to investing activities than operating activities, and therefore they are included with capital expenditures.

(2) Dispositions for the nine months ended September 30, 2010 include the receipt of $7.1 million in common shares of Trioil Resources Ltd as partial compensation for a non-core property disposition.

Exploration, development and land expenditures totaled $38.6 million for the three months ended September 30, 2011 as compared to $27.6 million for the third quarter of 2010. Current quarter capital expenditures were primarily directed towards heavy oil drilling in eastern Alberta, liquids-rich gas drilling at Karr and Edson in west central Alberta and undeveloped land acquisitions in the West Central District.

West central

During the third quarter, Perpetual drilled and completed three horizontal wells (3.0 net) and one (1.0 net) vertical well at Edson for liquids-rich gas, which were successfully put on production in October. In addition, $3.9 million was spent on Crown land purchases prospective for further Wilrich development.

In the fourth quarter, Perpetual drilled, completed and tested one (0.5 net) horizontal evaluation well to evaluate its new large land position, comprising 9,280 net acres (36.25 net sections) acquired during 2011, west of Perpetual's core Wilrich lands at Edson. The well recently flow tested at rates up to 13 MMcf/d with free condensate measured during the test at an average of 10 bbl per MMcf. Total natural gas liquids ("NGL") will be evaluated once the well commences production in late November but is expected to total 20 to 30 bbl per MMcf at a facility-restricted gross rate of 5 MMcf/d prior to year end. Plans are underway to follow up the initial success in this area in the first quarter of 2012, including construction of compression facilities to enhance production from the existing well and allow for optimal production from further follow-up development wells.

Perpetual is now currently executing on plans to drill two (1.1 net) additional horizontal Wilrich development wells in Edson and one (1.0 net) vertical exploration well to extend the Wilrich trend prior to year end. In the greater Edson area, Perpetual has now identified over 80 net horizontal drilling locations in the Wilrich formation for future development.

In addition, Perpetual successfully drilled and completed a horizontal Dunvegan (1.0 net) development well at Karr, targeting liquids-rich gas at 40 bbls per MMcf of NGLs. This well came on production at the end of October at 1,030 boe/d (5.0 MMcf/d of gas plus 200 bbl/d of NGLs). As a result of this activity, the Corporation has identified four additional Dunvegan horizontal follow up locations.

Additional expenditures in the third quarter included recompletions at Carrot Creek and Edson, and the completion of a vertical well at Karr which was drilled in the second quarter.

Mannville heavy oil

In the Mannville area of east central Alberta, Perpetual continued to focus on exploration and development of cretaceous-aged conventional heavy oil pools geographically synergistic with the Corporation's shallow gas assets. Perpetual drilled a total of nine (9.0 net) wells on this play during the third quarter. Results are as follows:

- Three (3.0 net) horizontal development oil wells were drilled expanding on the success of the second quarter 2011 program. These three wells have each averaged 144 bbl/d of oil production since being brought on line in mid-August;
- One vertical and one horizontal (2.0 net) wells were drilled on a new heavy oil pool. Early swabbing results in the horizontal well were very encouraging. Production from this pool will commence once approval for water disposal into the vertical well is received during the fourth quarter;
- Three gross (3.0 net) vertical exploratory tests were also drilled to help define new pools and will be followed up by future horizontal drilling;
- One (1.0 net) additional water disposal well was drilled to help optimize operating costs and minimize trucking in the area.

Since the end of the third quarter, Perpetual has drilled a total of six wells:

- One (1.0 net) horizontal well into a new pool which commenced production on October 26. This well has averaged over 125 bbl/d of oil since start up and continues to improve as production is optimized;
- One vertical delineation well, with a follow on horizontal development well (2.0 net), into a new pool in the Mannville area. This horizontal well is expected to commence production shortly;
- Two (2.0 net) development horizontal wells into an existing Lloyd formation pool. Preliminary swab results have exceeded average results for the area, indicating production from these wells should exceed expectations;
- One (1.0 net) additional Lloyd channel well has reached total depth and is expected to be on production within two weeks.

Drilling will continue through to the end of the year as capital is focused on growing oil production and reserves in this area, where the Corporation has over 123,000 net acres. Plans for the remainder of the fourth quarter include the drilling of one more vertical exploratory well targeting definition of another new Lloyd pool. In addition, 6 to 8 horizontal development wells will be drilled into established pools with production expected to commence prior to year end.

Bitumen

In May, the Corporation received an independent contingent resource report effective April 30, 2011 prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") for the Corporation's acreage in the Panny area of northeast Alberta. McDaniel recognized a best estimate of 618 MMbbl Discovered Bitumen Initially in Place ("DBIIP"). The best estimate gross recoverable contingent resource is estimated at 108 MMbbl based on the application of cyclic steam stimulation ("CSS"). Perpetual has submitted an application to the ERCB for a pilot project to test a novel recovery process which, if successful, would be less capital-intensive and more energy and cost efficient than CSS. This test is designed to determine the production characteristics of the reservoir at temperatures significantly below steam temperatures. Perpetual holds a 100 percent interest in the Panny properties.

McDaniel has now completed its independent resource assessment of Perpetual's oil sands leases in the Liege area. The resource assignments are for the Grosmont and Leduc carbonate formations at North and South Liege. McDaniel recognized a best estimate of 331.9 MMbbl DBIIP and a best estimate of 1,996.2 MMbbl Undiscovered Bitumen Initially In Place ("UBIIP") in the Liege area. The best estimate contingent resource and additional prospective resource are 66.2 MMbbl and 399.2 MMbbl respectively. McDaniel assigned bitumen resource estimates on the basis of three bitumen evaluation wells that were drilled in the first quarter of 2011 as well as existing legacy gas well control, and assumed that Steam Assisted Gravity Drainage ("SAGD") exploitation in carbonate reservoirs would currently be considered "technology under development", assigning a recovery factor of 20 percent to the 2.3 billion barrels of recognized resource. In both South and North Liege, Perpetual holds a 100 percent interest. Contingencies applicable to the Liege carbonate resource include SAGD as a technology under development in a carbonate reservoir, being in the early evaluation stage (insufficient delineation), economic concerns (not clear whether a future development project would be economic), regulatory issues (environmental and development applications not yet submitted), as well as lack of corporate intent to develop. An economic evaluation was not undertaken and therefore all resources assigned are currently unclassified with regard to economic status.

Warwick Gas Storage Inc. ("WGSI")

Gas storage expenditures decreased from $23.1 million for the third quarter of 2010 to $2.5 million for the current quarter. Prior period costs include expenditures related to facility construction, whereas third quarter 2011 expenditures were directed to the drilling of a horizontal well to increase the working gas capacity in the storage reservoir, as well as workover costs for existing wellbores. Capacity has been established at 17 Bcf for the second commercial storage cycle, which commenced April 1, 2011.

Acquisitions and dispositions

During the three months ended September 30, 2011, the Company spent $5.1 million on acquisitions, the majority of which was incurred to increase the inventory of Wilrich drilling locations in the greater Edson area.

Third quarter 2011 dispositions included a non-core asset in west central Alberta for net proceeds of $6.9 million, which resulted in a gain on disposition of $2.5 million. For the comparative quarter in 2010, the Company disposed of non-core properties located primarily in the Eastern District for net proceeds of $17.0 million.

Production

Production by core area and commodity

	Three months ended September 30		Nine months ended September 30	
	2011	2010	**2011**	2010
Gas (MMcf/d)				
Eastern District [1]	**98.2**	123.6	**104.3**	130.0
West Central District	**24.7**	19.7	**26.5**	17.6
Other	**0.6**	0.7	**0.5**	0.7
Total (MMcf/d)	**123.5**	144.0	**131.3**	148.3
Oil & NGL (bbl/d)				
Eastern District [1]	**718**	177	**501**	264
West Central District	**1,277**	990	**1,302**	884
Other	**-**	-	**-**	-
Total (bbl/d)	**1,995**	1,167	**1,803**	1,148
Total (MMcfe/d)				
Eastern District [1]	**102.6**	124.7	**107.3**	131.6
West Central District	**32.3**	25.6	**34.3**	22.9
Other	**0.6**	0.7	**0.5**	0.7
Total (MMcfe/d)	**135.5**	151.0	**142.1**	155.2
Deemed natural gas production (MMcf/d) [2]	**29.8**	24.6	**26.1**	25.1
Total plus deemed production (MMcfe/d) [2]	**165.3**	175.6	**168.2**	180.3

(1) In 2010, Perpetual had an 89 percent ownership interest in Severo Energy Corp. ("Severo"), a private company engaged in oil and gas exploration in Canada. Effective October 4, 2010. Perpetual purchased the remaining 11 percent interest in Severo and Severo became a wholly-owned subsidiary of the Corporation. As such, Severo production is included with the Eastern District.

(2) The deemed production volume describes all gas shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the Energy Resources and Conservation Board ("ERCB") or its predecessor the Alberta Energy and Utilities Board ("AEUB"), or through correspondence in relation to an AEUB ID 99-1 application. This deemed production volume is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen financial solution which is received monthly from the Alberta Crown as a reduction against other royalties payable.

Total actual plus deemed production for the third quarter averaged 165.3 MMcfe/d, down from 175.6 MMcfe/d for the same period in 2010. Production volumes decreased as a result of natural declines and dispositions totaling 5.2 MMcfe/d for the period, offset by production additions resulting from drilling activities in west central Alberta and the commencement of new heavy oil production from the Mannville area.

Natural gas production totaled 123.5 MMcf/d for the three months ended September 30, 2011 as compared to 144.0 MMcf/d for the third quarter of 2010. Production volumes decreased 14 percent due to the shut-in of approximately 8 MMcf/d of raw production (5.7 MMcf/d of sales) and subsequent sale of reserves at Liege ("Liege Assets") in November 2010, and asset dispositions, partially offset by production additions from successful drilling in the Wilrich formation in the West Central District. Over the past 12 months, capital programs have preferentially targeted oil and NGLs, thereby allowing natural gas production to decline in favor of investment to bring higher priced oil and NGLs onstream.

The production from the Liege Assets which were shut-in prior to the sale of the property on November 17, 2010 was subject to an interim shut-in decision by the ERCB announced on May 10, 2011. Perpetual retained operatorship of the Liege Assets in order to be eligible to receive the related gas over bitumen royalty adjustments once the decision was made, and began receiving these adjustments in respect of approximately 8.0 MMcf/d of deemed production on June 1, 2011 (see "Gas over bitumen royalty adjustments" in this MD&A). As a result of the Liege adjustments, deemed natural gas production increased 21 percent in the third quarter of 2011 relative to the same period in 2010.

Oil and NGL production averaged 1,995 bbl/d for the three months ended September 30, 2011, an increase of 71 percent from the third quarter of 2010 due to the commencement of production from the successful heavy oil drilling programs in east central Alberta and focused drilling for liquids-rich gas in the West Central District. Oil production from the Eastern District grew by over 300 percent, averaging 718 bbl/d for the quarter and exiting the quarter at close to 1,050 bbl/d. Oil and NGL production comprised 8.8 percent of Perpetual's total production in the third quarter.

Average production for the nine months ended September 30, 2011 decreased eight percent to 142.1 MMcfe/d from 155.2 MMcfe/d in the 2010 period due to the Liege shut-in and property dispositions, partially offset by the increase in production associated with the Edson Acquisition and subsequent development of the West Central District assets.

MARKETING

	Three months ended September 30		Nine months ended September 30	
Commodity prices	**2011**	2010	**2011**	2010
Reference prices				
AECO Monthly Index ($/Mcf)	**3.72**	3.72	**3.74**	4.31
AECO Daily Index ($/Mcf)	**3.66**	3.54	**3.77**	4.13
Alberta Gas Reference Price ($/Mcf) (1)	**3.51**	3.45	**3.55**	3.93
West Texas Intermediate ("WTI") light oil (US$/bbl)	**91.89**	76.04	**95.39**	76.79
Average Perpetual prices				
Natural gas				
Before derivatives ($/Mcf) (2)	**3.56**	3.80	**3.91**	4.27
Percent of AECO Monthly Index (%)	**96**	102	**104**	99
Including derivatives ("Realized" gas price) ($/Mcf)	**3.75**	6.02	**3.98**	6.92
Percent of AECO Monthly Index (%)	**101**	162	**106**	161
Oil and NGL				
Average realized price ($/bbl)	**70.15**	56.13	**71.28**	64.88
Natural gas equivalent				
Average realized price ($/Mcfe)	**4.46**	6.18	**4.58**	7.09

(1) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties. Alberta Gas Reference Price for September 2011 is an estimate.

(2) Natural gas price before derivatives includes physical forward sales contracts for which delivery was made during the reporting period but excludes realized gains and losses on derivatives.

AECO Monthly Index prices were unchanged at $3.72 per Mcf for the three months ended September 30, 2011 and 2010 as strong supply from shale gas plays in the United States continued to weigh on natural gas markets, despite lower year-over-year gas storage levels in North America. Natural gas prices before derivatives decreased from $3.80 per Mcf for the third quarter of 2010 to $3.56 per Mcf for the current three month period due to a negative prior period revenue adjustment booked in the current quarter that did not impact volumes. Natural gas prices before derivatives decreased eight percent to $3.91 per Mcf for the first nine months of 2011 from $4.27 per Mcf in 2010, as compared to a 13 percent decline in the AECO Monthly Index price for the same period. The decrease in AECO prices was partially offset by higher heat content gas in the West Central District and the inclusion of 10,000 GJ/d of fixed price physical natural gas sales at $7.75 per GJ for the first three months of 2011 in the Corporation's natural gas price.

Perpetual's average realized oil and NGL price increased 25 percent to $70.15 per bbl for the current quarter from $56.13 for the three months ended September 30, 2010, primarily due to higher WTI prices. The Corporation's capital programs target medium-quality crude oil at Mannville and NGLs in the West Central District, both of which receive a discount to WTI pricing.

The Corporation's average realized gas prices decreased to $3.75 per Mcfe and $3.98 per Mcfe, respectively for the third quarter and first nine months of 2011 from $6.02 per Mcfe and $6.92 per Mcfe for the comparable periods in 2010. The 2010 figures included realized gains on derivatives totaling $29.4 million for the third quarter and $107.4 million for the nine-month period, leading to the higher realized prices. Perpetual had anticipated a low natural gas price environment in 2011 and crystallized $37.3 million in gains on derivatives in the fourth quarter of 2010 related to 2011 financial natural gas contracts, in order to pre-fund a portion of its 2011 capital spending programs. This strategy had the effect of reducing the Corporation's realized gas price in the current period, while increasing the realized gas price for the last three months of 2010 to $7.83 per Mcf.

Risk management

Perpetual's gas price risk management strategy is focused on using derivatives to mitigate the effect of commodity price volatility on funds flow and dividends, to lock in economics on capital programs and acquisitions and to take advantage of perceived anomalies in natural gas markets. The Corporation uses both financial arrangements and physical forward sales to economically hedge up to a maximum of 60 percent of the trailing quarter's production including gas over bitumen deemed volumes in accordance with the limits under the Corporation's credit facility and Hedging and Risk Management Policy. Perpetual will also enter into foreign exchange swaps and physical or financial swaps related to the differential between natural gas prices at the AECO and NYMEX trading hubs in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Corporation's realized gas price. The term "derivatives" includes all financial and physical risk management contracts. Although Perpetual considers the majority of these risk management contracts to be effective economic hedges against potential commodity price volatility, the Corporation does not follow hedge accounting for its derivatives.

Perpetual's risk management activities are conducted by an internal Risk Management Committee under guidelines approved by the Corporation's Board of Directors. Perpetual's risk management strategy, though designed primarily to protect funds flow and dividends, is opportunistic in nature. Depending on management's perceived position in the commodity price cycle the Corporation may elect to reduce or increase its risk management position within the approved guidelines. The Corporation mitigates credit risk by entering into economic hedging contracts with financially sound, credit-worthy counterparties.

The Corporation recorded an unrealized loss on derivatives of $5.4 million for the three months ended September 30, 2011, due to the change in fair market value of foreign currency contracts entered into during the period, and to the settlement of financial fixed-price natural gas sale contracts during the period, which has the effect of converting unrealized gains to realized gains. In addition, a loss of $1.4 million was recorded on the forward sale contracts for future natural gas delivery related to the gas storage project, due to the change in mark to market value of the obligation.

Financial and forward sales contracts as of September 30, 2011 are disclosed in note 14 to the Corporation's interim consolidated financial statements as at and for the three and nine months ended September 30, 2011. Financial and physical forward sales arrangements (net of related financial and physical fixed-price natural gas purchase contracts) at the AECO trading hub as at November 7, 2011 are as follows:

Type of Contract	Volumes at AECO (GJ/d)(1)	% of 2011 Forecast Production(3)	Price ($/GJ)(1)	Futures Market ($/GJ) (2)	Term
Financial	20,000	11	3.21	3.43	November 2011
Financial - NYMEX	5,000	3	3.91	3.70	December 2011

(1) Average price calculated using weighted average price for net open sell contracts.
(2) Futures market reflects AECO/NYMEX settled and forward market prices as at November 7, 2011. NYMEX volumes are in MMbtu and prices are in $US per MMbtu.
(3) Calculated using 185,000 GJ/d and includes actual and gas over bitumen deemed projected production volumes.

As part of Perpetual's risk management strategy, the Corporation has also sold forward financial call options to counterparties to purchase natural gas from Perpetual at strike prices in excess of current forward prices. Option premiums were included in cash flow from operations in the period received. There were no commodity-based call option contracts outstanding as of November 7, 2011.

The Corporation also enters into financial and forward physical gas sales arrangements to fix the basis differential between the NYMEX and AECO trading hubs. The price at which these contracts settle is equal to the NYMEX index less a fixed basis amount. Oustanding basis contracts (net of related purchase contracts) as of November 7, 2011 are as follows:

Type of Contract	Volumes at NYMEX (MMBtu/d)	Price (US$/MMBtu)	Term
Financial	50,000	(0.46)	December 2011 – March 2012
Financial	50,000	(0.57)	April – October 2012

At September 30, 2011 the Corporation had entered into a financial and forward physical oil sales arrangement to fix the basis differential between the WTI and western Canada trading hubs as follows. The price at which this contract settles is equal to the WTI index less a fixed basis amount.

Type of Contract	Perpetual Sold/Bought	Volumes at WTI (bbls/d)	Price (US$/bbls)	Term
Financial	sold	400	($17.35)	January – December 2012

Perpetual also entered into the following costless collar oil sales arrangement, to reduce exposure to fluctuations in the WTI index:

Type of Contract	Perpetual Sold/Bought	Volumes at WTI (bbls/d)	Price (US$/bbls)	Term
Call	sold	500	$89.00	January – December 2012
Call	sold	500	$91.00	January – December 2012
Call	sold	500	$97.00	January – December 2012
Put	bought	(500)	$80.00	January – December 2012
Put	bought	(500)	$82.00	January – December 2012
Put	bought	(500)	$85.00	January – December 2012

Perpetual has also entered into the following U.S. dollar forward sales arrangements to limit the Corporation's exposure to the effects of strength in the Canadian dollar on natural gas prices.

Type of Contract	Perpetual Sold/Bought	Notional $USD/month	Exchange rate ($CAD/$USD)	Term
Financial	bought	($1,000,000)	$1.0085	January 2012 – December 2012
Financial	bought	($2,000,000)	$1.0535	January 2012 – December 2012

In addition, the Corporation has sold call options expiring on December 31, 2011 in order to enhance the exchange rate on the forward sales contracts described above as follows:

Type of Contract	Perpetual Sold/Bought	Notional $USD/month	Strike exchange rate ($CAD/$USD)	Term
Call	sold	$1,000,000	$1.0200	January 2012 – December 2012
Call	sold	$2,000,000	$1.0500	January 2012 – December 2012

Perpetual entered into forward financial power contracts to mitigate the risk to operating costs associated with fluctuations in power prices at the WGSI facility. Contracts outstanding at November 7, 2011 are as follows:

Type of Contract	Perpetual Sold/Bought	Volume (MWh)	Price ($CAD/MWh)	Term
Financial	bought	(7,469.76)	$ 60.88	December 2011
Financial	bought	(7,261.44)	$ 63.77	January 2012
Financial	bought	(5,950.80)	$ 64.13	February 2012
Financial	bought	(5,133.60)	$ 62.58	March 2012
Financial	bought	(6,480.00)	$ 76.00	January – March 2013

FINANCIAL RESULTS

Revenue

Revenue ($ thousands)	Three months ended September 30 **2011**	2010	Nine months ended September 30 **2011**	2010
Natural gas revenue, before derivatives (1)	**40,446**	50,410	**140,017**	172,687
Oil and NGL revenue	**12,880**	6,019	**35,122**	20,325
Gas storage revenue	**5,074**	4,825	**11,258**	5,487
Realized gains on derivatives (2)	**2,194**	29,372	**2,768**	105,593
Call option premiums received (3)	**-**	-	**-**	1,851
Total revenue	**60,594**	90,626	**189,165**	305,943

(1) Includes revenues related to physical forward sales contracts which settled during the period.
(2) Realized gains on financial instruments include settled financial forward contracts and options.
(3) Call option premiums received are included in the calculation of the Corporation's realized gas price and funds flows.

Natural gas revenue decreased to $40.4 million for the current quarter from $50.4 million for the third quarter of 2010 due to a 14 percent decrease in production levels, resulting primarily from the Liege shut-in and asset dispositions. Oil and NGL revenue increased $6.9 million from the three months ended September 30, 2010, making up almost 70 percent of the drop in natural gas revenues, as a result of a 71 percent increase in oil and NGL production coupled with an increase in oil and NGL prices of $14.02 per bbl.

Gas storage revenue is derived from injecting, storing and withdrawing natural gas from the WGSI facility on behalf of third parties, and is recorded in accordance with the terms of the storage contracts. Gas storage revenue increased to $5.1 million and $11.3 million for the three and nine month periods ending September 30, 2011, respectively from $4.8 million and $5.5 million for the comparative periods in 2010 as the WGSI facility commenced operations on May 3, 2010. Facility capacity was increased from 8 to 17 Bcf for the second operational cycle starting April 1, 2011 as a result of positive reservoir performance through the test cycle and additional drilling activities.

Total revenue decreased 33 percent to $60.6 million for the three months ended September 30, 2011 compared to $90.6 million for the third quarter of 2010 primarily due to a $27.2 million decrease in realized gains on derivatives related to the Corporation's gas price management program. Revenue for the nine months ended September 30, 2011 decreased 38 percent to $189.2 million from $305.9 million for 2010, also primarily as a result of lower realized gains on derivatives. Revenue for the three and nine month comparative periods in 2010 was enhanced by $27.5 million and $90.9 million, respectively in gains related to the termination of forward financial sales contracts in advance of their maturity dates, which were completed to reduce debt levels and facilitate strategic acquisitions related to the Corporation's commodity diversification strategy.

Funds flow

Funds flow reconciliation	Three months ended September 30 **2011** $ millions	**2011** $/Mcfe	2010 $ millions	2010 $/Mcfe	Nine months ended September 30 **2011** $ millions	**2011** $/Mcfe	2010 $ millions	2010 $/Mcfe
Production (Bcfe)	**12.4**		13.9		**38.8**		42.4	
Revenue [1]	**60.6**	**4.87**	90.6	6.52	**189.2**	**4.88**	305.9	7.22
Royalties	**(4.0)**	**(0.32)**	(3.4)	(0.25)	**(16.4)**	**(0.42)**	(19.4)	(0.46)
Operating costs	**(22.5)**	**(1.81)**	(24.9)	(1.79)	**(64.0)**	**(1.65)**	(70.3)	(1.66)
Transportation	**(2.5)**	**(0.20)**	(2.9)	(0.21)	**(8.1)**	**(0.21)**	(9.1)	(0.22)
Operating netback [3]	**31.6**	**2.53**	59.4	4.27	**100.7**	**2.60**	207.1	4.88
Gas over bitumen royalty adjustments	**3.7**	**0.30**	2.8	0.20	**9.4**	**0.24**	9.6	0.23
Lease rentals	**(1.1)**	**(0.09)**	(1.4)	(0.10)	**(2.7)**	**(0.07)**	(3.1)	(0.07)
General and administrative [2]	**(6.2)**	**(0.50)**	(8.0)	(0.58)	**(22.2)**	**(0.57)**	(25.1)	(0.59)
Interest on debt	**(1.4)**	**(0.11)**	(2.6)	(0.19)	**(4.8)**	**(0.12)**	(9.2)	(0.21)
Interest on senior notes	**(3.2)**	**(0.25)**	-	-	**(7.1)**	**(0.18)**	-	-
Interest on convertible debentures [2]	**(4.1)**	**(0.33)**	(4.1)	(0.29)	**(12.2)**	**(0.32)**	(12.3)	(0.29)
Funds flow [2] [3]	**19.3**	**1.56**	46.1	3.31	**61.1**	**1.58**	167.0	3.95

(1) Revenue includes realized gains and losses on derivatives, call option premiums received and gas storage revenue.
(2) Excludes non-cash items.
(3) This is a non-GAAP measure; see "Other non-GAAP measures" in this MD&A.

Royalties

Royalty expense increased 18 percent to $4.0 million for the three months ended September 30, 2011 from $3.4 million for the comparative period in 2010, primarily due to lower gas cost allowance credits in the current quarter as compared to previous periods. As production and operating costs at Perpetual's northeast Alberta shallow gas properties have declined, the Crown's share of operating costs has also declined, leading to lower gas cost allowance recoveries. Royalty expense for the nine months ended September 30, 2011 totaled $16.4 million, a decrease of $3.0 million from 2010, due to lower natural gas prices and production levels, partially offset by an increase in oil and NGL revenues. The Corporation's average royalty rate on oil, natural gas and NGL revenues before derivatives increased to 7.4 percent for the three months ended September 30, 2011 compared to 5.9 percent for the third quarter of 2010, due to lower gas cost allowance credits and increasing revenue in the West Central District, which attracts higher royalty rates than Perpetual's Eastern District assets due primarily to higher average well productivity and NGL content.

Operating costs

Operating costs for the three months ended September 30, 2011 decreased $2.4 million from the third quarter of 2010 due to lower labor charges and higher processing fee recoveries. Unit operating costs totaled $1.81 per Mcfe for the current period as compared to $1.79 per Mcfe for the three months ended September 30, 2010 as lower costs were offset by reduced natural gas production levels. Operating costs for the first nine months of 2011 decreased to $1.65 per Mcfe from $1.66 per Mcfe in 2010, primarily due to reductions in labor and equipment costs offset by lower natural gas production.

Transportation costs

Transportation costs decreased to $2.5 million and $8.1 million respectively for the three and nine month periods ended September 30, 2011 from $2.9 million and $9.1 million for the comparative periods in 2010 due to lower natural gas production levels. Unit transportation costs for all periods were stable at $0.20 to $0.22 per Mcfe.

Operating netback

Perpetual's operating netback decreased by $27.8 million to $31.6 million for the three months ended September 30, 2011 from $59.4 million for same period in 2010, due primarily to a decrease in realized gains on derivatives. Perpetual's operating netback for the third quarter of 2010 included $27.5 million in gains related to the early termination of hedging contracts.

Operating netback reconciliation	($ millions)
Natural gas price decrease before derivatives	(3.2)
Natural gas production decrease	(6.8)
Oil and NGL price increase before derivatives	1.5
Oil and NGL production increase	5.4
Decrease in gains on derivatives	(27.2)
Gas storage revenue increase	0.2
Royalty expense increase	(0.6)
Operating cost decrease	2.4
Transportation cost decrease	0.5
Decrease in operating netback	(27.8)

Gas over bitumen royalty adjustments

In 2004 and 2005 the Government of Alberta enacted amendments to the royalty regulation with respect to natural gas ("Royalty Regulation"), which provide a mechanism whereby the Government may prescribe additional royalty components to effect a reduction in the royalty calculated through the Crown royalty system for operators of gas wells which have been denied the right to produce by the AEUB, or its successor the ERCB as a result of certain bitumen conservation decisions. The formula for calculation of the royalty reduction provided in the Royalty Regulation is:

0.5 x ((deemed production volume x 0.80) x (Alberta Gas Reference Price - $0.3791/GJ))

The Corporation's net deemed production volume for purposes of the royalty adjustment was 29.8 MMcf/d in the third quarter of 2011. Deemed production represents all Perpetual natural gas production shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the AEUB or ERCB, or through correspondence in relation to an AEUB ID 99-1 application. In accordance with IL 2004-36, the deemed production volume related to wells shut-in is reduced by ten percent per year on the anniversary date of the shut-in order. Deemed production increased 21 percent from 24.6 MMcf/d for the three months ended September 30, 2010 due to the ERCB's interim shut-in decision announced on May 10, 2011 in respect of the Liege Assets, which added an additional 8 MMcf/d to Perpetual's deemed production effective June 1, 2011 for the purpose of calculating the monthly gas over bitumen royalty adjustments received.

The majority of royalty adjustments received have been recorded on Perpetual's balance sheet rather than reported as income as the Corporation cannot determine if, when or to what extent the royalty adjustments may be repayable through incremental royalties if and when gas production recommences. Royalty adjustments may be repayable to the Crown in the form of an overriding royalty on gas production from wells which resume production within the gas over bitumen area. However, all royalty adjustments are recorded as a component of funds flow.

Perpetual has disposed of certain shut-in gas wells in the gas over bitumen area. As part of certain of these disposition agreements, the Corporation continues to receive the gas over bitumen royalty adjustments related to the sold wells, although the ownership of the natural gas reserves is transferred to the buyer. As such, any overriding royalty payable to the Crown when gas production recommences from the affected wells is no longer Perpetual's responsibility. As a result of this disposition, the gas over bitumen royalty adjustments received by the Corporation for the affected wells are now considered revenue since they will not be repaid to the Crown.

Gas over bitumen royalty adjustments are not paid to Perpetual in cash, but are a deduction from the Corporation's monthly natural gas royalty invoices. In periods of very low gas prices, the Corporation's net Crown royalty expenses have been too low to recover the full amount of the gas over bitumen royalty adjustments, and as such royalty adjustments for past periods will be recovered in future periods. Eventual realization of the royalty adjustments is highly likely as deemed production is reduced by ten percent annually, whereas the Corporation is focused on growing production and reserves year over year through capital spending programs, complemented with strategic acquisitions. As of September 30, 2011, Perpetual has accumulated $9.3 million (December 31, 2010 - $8.5 million) of gas over bitumen adjustments receivable which have been netted against the gas over bitumen royalty obligation on the statement of financial position.

A reconciliation of the gas over bitumen royalty obligation is provided below:

Balance, January 1, 2010	77,167
Royalty adjustments	12,303
Royalty adjustments classified as revenue	(15,616)
Royalty adjustments not yet received	(3,357)
Balance, December 31, 2010	70,497
Royalty adjustments	9,434
Royalty adjustments classified as revenue	(5,448)
Less: royalty adjustments not yet received	(845)
Balance, September 30, 2011	**73,638**

General and administrative expenses

	Three months ended September 30		Nine months ended September 30	
General and administrative expenses	**2011**	2010	**2011**	2010
Cash general & administrative	**6,234**	7,892	**22,176**	24,964
Share based compensation (1)	**668**	1,604	**3,676**	3,927
Total general & administrative	**6,902**	9,496	**25,852**	28,891

(1) Non-cash item

General and administrative costs for the first nine months of 2011 totaled $25.9 million as compared to $28.9 million for the comparable period in 2010 as a result of lower consulting and professional fees. Prior year costs also included expenses related to the conversion from an income trust into a corporation. General and administrative expenses decreased 27 percent to $6.9 million for the three months ended September 30, 2011 from $9.5 million for the three months ended September 30, 2010 due to lower salaries expense, professional fees and share based compensation costs.

Finance expenses

Interest expense decreased to $1.4 million and $4.8 million for the three and nine months ended September 30, 2011, respectively from $3.0 million and $9.5 million for the comparative periods in 2010 due to lower borrowings under the credit facility as a result of the issuance of $150 million in senior notes in the first quarter of 2011. Interest expense on senior notes totaled $3.4 million and $7.4 million for the three and nine months ended September 30, 2011.

Interest on convertible debentures for the three and nine months ended September 30, 2011 totaled $5.0 million and $14.9 million respectively, compared to $5.0 million and $14.5 million incurred for the three and nine months ended September 30, 2010. The increase in the nine month figures relates to the issue of a new series of seven percent convertible debentures in May 2010, which replaced a series of 6.5 percent debentures that were repaid on June 30, 2010.

Funds flow

Funds flow netbacks decreased 53 percent to $1.56 per Mcfe in the third quarter of 2011 from $3.31 per Mcfe in the comparable period for 2010, driven primarily by lower realized gains on financial instruments and higher finance expenses, partially offset by a reduction in general and administrative costs. These items were partially offset by increased netbacks for oil and liquids production, which measured 8.8 percent of the Corporation's production portfolio, as compared to 4.6 percent for the 2010 period. As a result of the decrease in netbacks, funds flow decreased to $19.3 million ($0.13 per common share) from $46.1 million ($0.32 per common share) for the third quarter of 2010. Funds flow for the nine months ended September 30, 2011 totaled $61.1 million ($0.41 per common share) as compared to $167.0 million ($1.19 per common share) for the first nine months of 2010. The decrease was caused primarily by lower realized gains on derivatives and reduced natural gas production and prices, partially offset by diversified funds flow from oil and NGL production and gas storage operations.

Decommissioning obligation

The Corporation's decommissioning obligation is estimated internally based on Perpetual's net ownership interest in all wells and facilities and estimated costs to abandon wells, decommission facilities and reclaim leases and roads, and is discounted at a risk-free interest rate to arrive at a net present value figure. The timing of decommissioning expenditures is estimated based on the reserve life of assets according to the Corporation's external reserve report prepared as of December 31, 2010. These expenditures are currently expected to occur over the next 25 years with the majority of costs incurred between 2015 and 2025. Perpetual's decommissioning obligations increased from $236.2 million at December 31, 2010 to $251.6 million at September 30, 2011 due to an increase in the discount rate used to measure the obligations, and accretion expense of $5.9 million for the first nine months of 2011.

Exploration and evaluation expenses

Exploration costs include lease rentals paid on undeveloped lands, seismic expenditures, dry hole costs and expired leases. Exploration expenses increased to $4.8 million for the three months ended September 30, 2011 from $3.7 million for the third quarter of 2010 due primarily to an increase lease expiries. For the first nine months of 2011 exploration expenses increased to $11.9 million from $11.4 million for 2010 due to higher land expiries and seismic expenditures as compared to prior year.

Depletion and depreciation

Depletion and depreciation ("D&D") expense decreased from $57.4 million and $172.1 million for the three and nine months ended September 30, 2010 to $28.7 million and $89.0 million for the three and nine month periods in 2011 due to a 44 percent average decrease in Perpetual's depletion rates. In 2010 and prior years, D&D expense was calculated based on proved developed reserves for exploration and development costs and total proved reserves for acquisition costs. In 2011, as part of the transition to International Financial Reporting Standards ("IFRS"), the Corporation elected to use total proved and probable reserves, incorporating future development costs, to measure D&D expense. The effect of this change was to increase the useful life of the Corporation's oil and gas properties and reduce D&D expense compared to the previous methodology. Perpetual believes that the current methodology is a better reflection of the useful life of the Corporation's assets.

Income taxes

Perpetual recorded deferred tax expense of $0.4 million and $0.3 million for the three and nine months ended September 30, 2011 (three and nine months ended September 30, 2010 – $2.7 million), related to timing differences between book and tax values of the Corporation's gas storage assets. Deferred income tax is a non-cash item and does not affect the Corporation's funds flows or its cash available for dividends.

At September 30, 2011, the Corporation's consolidated income tax pools are estimated to be $865 million. Actual tax pool amounts will vary as tax returns are finalized and filed.

Net loss

The Corporation reported a net loss of $24.3 million ($0.17 per basic and diluted common share) for the three months ended September 30, 2011 as compared to a net loss of $16.3 million ($0.11 per basic and diluted common share) for the 2010 period. The higher net loss is due to lower realized gains on derivatives, higher finance charges and unrealized losses on marketable securities and the gas storage obligation. Year-to-date in 2011 Perpetual reported a loss of $57.2 million ($0.39 per basic and diluted common share) as compared to a net loss in 2010 of $72.5 million ($0.52 per basic and diluted common share), as a result of lower D&D expense partially offset by lower funds flows. In the 2010 period distributions on trust units were recorded as expenses.

SUMMARY OF QUARTERLY RESULTS

Quarterly earnings in the following summary are presented in accordance with GAAP for periods ending prior to the transition to IFRS on January 1, 2011.

Quarterly results				Three months ended
($ thousands except where noted)	**Sep 30, 2011**	Jun 30, 2011	Mar 31, 2011	Dec 31, 2010
Oil and natural gas revenues (1)	**58,400**	67,097	60,900	61,718
Oil and natural gas production (MMcfe/d)	**135.5**	150.3	140.7	145.1
Funds flow (2)	**19,318**	17,852	23,923	70,509
Per common share - basic	**0.13**	0.12	0.16	0.48
Net loss	**(24,343)**	(5,626)	(27,260)	(19,874)
Per common share - basic	**(0.17)**	(0.04)	(0.18)	(0.13)
- diluted	**(0.17)**	(0.04)	(0.18)	(0.13)
Realized commodity price ($/Mcfe) (3)	**4.46**	4.61	4.68	7.83
Average AECO Monthly Index price ($/Mcf)	**3.72**	3.74	3.77	4.13

Quarterly results				Three months ended
($ thousands except where noted)	Sep 30, 2010	June 30, 2010	Mar 31, 2010	Dec 31, 2009
Oil and natural gas revenues (1)	61,254	64,108	73,139	56,987
Oil and natural gas production (MMcfe/d)	151.0	165.2	149.2	145.9
Funds flow (2)	46,078	36,162	84,419	39,409
Per common share - basic	0.32	0.25	0.66	0.32
Net earnings (loss)	(1,710)	(44,211)	37,250	(11,287)
Per common share - basic	(0.01)	(0.31)	0.29	(0.09)
- diluted	(0.01)	(0.31)	0.29	(0.09)
Realized commodity price ($/Mcfe) (3)	6.18	5.54	9.78	5.87
Average AECO Monthly Index price ($/Mcf)	3.72	3.86	5.36	4.23

(1) Excludes realized gains (losses) on derivatives, but includes gas storage revenue.
(2) These are non-GAAP measures; see "Other non-GAAP measures" in this MD&A.
(3) Realized commodity price includes natural gas, oil and NGL sales, realized gains and losses on financial hedging and physical forward sales contracts.

Oil and natural gas revenues are a function of production levels, production mix and commodity prices. Revenues were highest in the first quarter of 2010 when AECO prices were highest, averaging $5.36 per Mcf. Perpetual uses derivatives to mitigate the effect of volatility in AECO prices on funds flows, and in recent quarters has shifted its exploration and asset development strategy to focus on oil and liquids-rich natural gas. Therefore funds flows will trend with Perpetual's production mix, realized commodity prices and changes in production levels. Funds flows were highest in the first quarter of 2010 as a result of a realized price of $9.78 per Mcfe. Funds flows are lowest in the second and third quarters of 2011 due to reductions in realized gains on derivatives relative to previous quarters, leading to realized prices of $4.61 per Mcfe and $4.46 per Mcfe, respectively.

Net earnings (losses) are a function of funds flows and non-cash charges, such as D&D, impairment losses and unrealized gains (losses) on derivatives. Due to the volatility of natural gas prices and the Corporation's risk management position, net earnings (losses) also fluctuated with changes in AECO gas prices as of each reporting date. Net earnings were highest in the first quarter of 2010 as a result of high funds flows and unrealized gains on derivatives of $16.7 million. The net loss in the second quarter of 2010 resulted from an unrealized loss of $34.4 million on the change in mark-to-market value of Perpetual's derivatives during the period. Net losses in the 2011 quarters are due to low funds flows and unrealized losses on derivatives.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Capitalization and financial resources

($ thousands except per common share and percent amounts)	**Sep 30, 2011**	Dec 31, 2010
Long term bank debt	**98,070**	182,612
Senior notes, measured at principal amount	**150,000**	-
Working capital deficiency (surplus) [(1)]	**22,234**	31,934
Convertible debentures, measured at principal amount	**234,897**	234,897
Net debt	**505,201**	449,443
Common shares outstanding (thousands)	**147,236**	148,284
Market price at end of period ($/common share)	**1.98**	3.93
Market value of common shares	**291,527**	582,756
Total capitalization [(1)]	**796,728**	1,032,199
Net debt as a percentage of total capitalization (%)	**63.4**	43.5
Trailing four quarters funds flow [(1)]	**133,909**	237,470
Net debt to annualized funds flow ratio (times) [(1)]	**3.8**	1.9

(1) These are non-GAAP measures; see "Other non-GAAP measures" in this MD&A.

Bank debt

Perpetual has a revolving credit facility with a syndicate of Canadian chartered banks (the "Credit Facility"). The revolving nature of the facility expires on May 29, 2012 if not extended. The borrowing base on the Credit Facility is currently $210 million, with the next borrowing base review scheduled for November 30, 2011. At current interest rates and applicable margins, the effective interest rate on the Corporation's bank debt is approximately 5.4 percent. Collateral for the credit facility is provided by a floating-charge debenture covering all existing and acquired property of the Corporation as well as unconditional full liability guarantees from all subsidiaries except WGSI in respect of amounts borrowed under the facility. Bank debt drawn on Perpetual's credit facility decreased $84.5 million from December 31, 2010 due to proceeds received from the issuance of senior notes on March 15, 2011, partially offset by dividends and capital expenditures in excess of funds flows for the nine month period. In addition to amounts outstanding under the credit facility Perpetual has outstanding letters of credit in the amount of $7.6 million.

Working capital deficiency

Working capital deficiency decreased to $22.2 million at September 30 from $31.9 million as at December 31, 2010. The Corporation will typically experience working capital deficiencies as accounts receivable for production revenues are received 25 days after month-end, whereas operating and capital expenditures are usually paid on a 30 to 60 day timeline. Working capital deficiencies can be paid through future revenues or drawings on the Credit Facility, as appropriate.

Gas storage arrangement

As part of the Corporation's semi-annual borrowing base redetermination in May 2010, Perpetual's gas reserves in the Warwick Glauconitic-Nisku A pool were removed from the assets dedicated to secure the syndicated banking facility. In order to provide non-bank funding for a portion of the WGSI Facility, Perpetual entered into a gas sale and storage transaction which includes the forward sale of these reserves, currently in the storage reservoir, that provide the "cushion" gas for the storage operation. In accordance with the storage arrangement funding, Perpetual received $31.6 million on June 30, 2010 and an additional $10.0 million ($9.9 million net of transaction fees) in the first quarter of 2011, both of which have been recorded as a gas storage arrangement liability on the Corporation's statement of financial position. In exchange for the funds received, Perpetual agreed to deliver eight Bcf of natural gas to the counterparty during the first quarter of 2013. Perpetual has since entered into offsetting transactions to extend the delivery term to the first quarter of 2015, and approximately 4.5 Bcf of the delivery volume was extended to the first quarter of 2016. The gas storage liability on the statement of financial position represents the estimated net present fair value of the future delivery obligation and as such, the liability will be accreted until its maturity, using the effective interest rate method. A derivative asset or liability and a corresponding unrealized gain or loss on derivatives on the statement of earnings are also recorded related to the change in the forward price curves for natural gas on the delivery date. For the current quarter Perpetual recorded an unrealized loss of $1.3 million on the gas storage arrangement, due primarily to the extension of the delivery term.

Senior notes

On March 15, 2011 Perpetual issued $150 million of seven-year senior unsecured notes (the "Senior Notes"). The Senior Notes are direct senior unsecured obligations of Perpetual ranking *pari passu* with all other present and future unsecured and unsubordinated indebtedness of the Corporation. The Senior Notes bear interest at 8.75%, payable semi-annually, and mature on March 15, 2018. Net proceeds from the offering of approximately $146.2 million after issue costs were used initially to repay amounts outstanding under the Credit Facility.

Convertible debentures

As at September 30, 2011, the Corporation had three series of convertible debentures outstanding: 6.5 percent convertible debentures issued in June 2007 (6.50% Debentures), 7.25 percent convertible debentures issued in April 2006 and amended in 2009 (7.25% Debentures) and 7.0 percent convertible debentures issued in May 2010 (7.0% Debentures). All series of debentures are repayable on the maturity date in cash or in common shares, at the option of Perpetual. The Corporation's intent is to settle the 6.50% Debentures in cash on the maturity date.

Convertible debentures	6.50%	7.25%	7.00%
Principal issued ($ millions)	75.0	100.0	60.0
Principal outstanding ($ millions)	74.9	100.0	60.0
Trading symbol on the Toronto Stock Exchange	PMT.DB.C	PMT.DB.D	PMT.DB.E
Maturity date	June 30, 2012	January 31, 2015	December 31, 2015
Conversion price ($ per common share)	14.20	7.50	7.00
Fair market value ($ millions)	68.7	90.0	49.8

Fair values of debentures are calculated by multiplying the number of debentures outstanding at September 30, 2011 by the quoted market price per debenture at that date. None of the debentures were converted into common shares during the three months ended September 30, 2011.

Net debt to trailing four quarters funds flow increased to 3.8 times as at September 30, 2011 compared to 1.9 times as at December 31, 2010, due to a decrease in funds flows for the period and an increase in net debt. A reconciliation of the increase in net debt from December 31, 2010 to September 30, 2011 is as follows:

Reconciliation of net debt (1)	($ millions)
Net debt, December 31, 2010	449.4
Capital expenditures (exploration & development, gas storage and other)	70.9
Dispositions, net of acquisitions	(29.2)
Funds flow (1)	(41.8)
Dividends	22.2
Expenditures on decommissioning obligations	1.8
Funds received for gas storage arrangement	(9.9)
Issue costs on Senior Notes	3.7
Repurchase of common shares, less proceeds from exercise of share options	2.3
Unrealized loss on marketable securities	2.7
Receipt of gas over bitumen royalty adjustments not previously received	(1.6)
Net debt, June 30, 2011	470.5
Capital expenditures (exploration & development, gas storage and other)	41.4
Dispositions, net of acquisitions	(2.0)
Funds flow (1)	(19.3)
Dividends	6.6
Expenditures on decommissioning obligations	2.6
Repurchase of common shares, less proceeds from exercise of share options	1.5
Unrealized loss on marketable securities	1.4
Gas over bitumen royalty adjustments not yet received	2.5
Net debt, September 30, 2011	**505.2**

(1) These are non-GAAP measures; see "Other non-GAAP measures" in this MD&A.

Normal course issuer bid ("NCIB")

Perpetual currently has an NCIB in place with the Toronto Stock Exchange ("TSX") allowing the Corporation to repurchase up to 7.4 million issued and outstanding common shares on the open market through the TSX. The Bid commenced on April 27, 2011 and will terminate on April 26, 2012 or such earlier time as the Bid is completed or terminated at the option of Perpetual. Management of Perpetual believes that, from time to time, the market price of the Common Shares may not fully reflect the underlying value of the Common Shares and that at such times the purchase of Common Shares would be in the best interests of Perpetual. Such purchases will increase the proportionate interest of, and may be advantageous to, all remaining shareholders. During the third quarter of 2011 Perpetual repurchased and cancelled 473,400 common shares at an average price of $3.13 per common share for a total cost of $1.5 million.

Dividends

Dividends are determined monthly by the Board of Directors of the Corporation taking into account Perpetual's forecasted production, capital spending and cash flow, forward natural gas price curves, the Corporation's current hedging position, targeted debt levels and debt repayment obligations. The following items are considered in arriving at cash dividends to Shareholders:

- Exploration and development expenditures;
- Projected production additions;
- Debt repayments to the extent required or deemed appropriate by management to preserve balance sheet strength for future opportunities;
- Base production forecasts;
- Current financial and physical forward natural gas sales contracts;
- Forward market for natural gas prices;
- Site reclamation and abandonment expenditures; and
- Working capital requirements.

Dividends for the third quarter of 2011 totaled $6.6 million or $0.045 per common share consisting of $0.015 per common share paid on August 15, September 15 and October 17. The Corporation's payout ratio, which is the ratio of dividends to funds flow, was 34.2 percent in the current quarter as compared to 47.3 percent for the third quarter of 2010.

On October 19, 2011 the Corporation announced that future dividend payments would be suspended until further notice. Continued payment of a dividend is not sustainable given the continued weakness in natural gas prices, and will inhibit Perpetual's continuing efforts to implement its strategy of commodity and asset base diversification.

Notwithstanding a dramatic decrease in natural gas prices from June of 2008 forward, and the fact that Perpetual's production was composed almost entirely of conventional shallow natural gas, the Corporation has to date been able to issue cumulative dividends (including distributions paid since the inception of Perpetual's successor, Paramount Energy Trust) of $14.519 per common share. The historic decline in natural gas prices and related funds flow reductions were offset in large part through a successful hedging program, which contributed to the Corporation being able to continue paying a dividend while pursuing its asset base diversification strategy. However, going forward, persistent growth in North American natural gas supply, coupled with continued strength in gas drilling rig activity, suggest that a recovery in gas prices may be further delayed. As favorable natural gas hedging opportunities are no longer available in the current market, directing funds flow to the execution of the diversification strategy is paramount. Perpetual believes that its asset and commodity diversification strategy is central to preserving and growing value for Shareholders.

The continued execution of the strategies to diversify commodity mix and create value, capitalizing on Perpetual's substantial inventory of economic opportunities, is expected to grow funds flow. Combined with ongoing debt reduction initiatives, including asset sales, stronger diversified funds flows will strengthen the Corporation's balance sheet. The suspension of the dividend was necessary to drive Perpetual's commitment to maximize Shareholder value.

Re-instatement of a dividend in the future will be evaluated at such time as Perpetual's balance sheet has regained strength and commodity prices and costs support a sustainable model where excess free funds flow, over and above capital investments, is once again being generated for distribution to Shareholders.

Outlook and sensitivities

Estimated capital spending of $31 million for the last three months of 2011 will be directed primarily to oil and liquids-rich projects with the goal of continuing to accelerate Perpetual's commodity diversification strategy.

The following sensitivity table reflects Perpetual's projected realized gas price and funds flow for the fourth quarter of 2011, as well as projected ending 2011 net debt at certain AECO natural gas price levels. These sensitivities incorporate a realized oil and NGL price of $78 per bbl, operating costs of $23 million, cash general and administrative expenses of $8 million and an interest rate on bank debt of 5.4 percent.

Fourth quarter 2011 funds flow outlook	Average AECO Monthly Index gas price for the fourth quarter of 2011 ($/GJ) [(1)] $3.00	$4.00	$5.00
Natural gas production (MMcf/d)	123	123	123
Oil and NGL production (bbl/d)	2,850	2,850	2,850
Realized gas price ($/Mcf) [(1)]	3.22	4.20	5.20
Total funds flow ($millions) [(2)]	15	26	38
Per common share ($/common share)	0.10	0.18	0.26
Ending net bank debt ($millions) [(2)]	133	122	110
Ending net debt ($millions) [(2)(3)]	518	507	495
Ending net bank debt to annualized funds flow ratio (times) [(2)(3)]	2.3	1.2	0.7
Ending total net debt to annualized funds flow ratio (times) [(2)(3)]	8.9	4.8	3.3

(1) The current settled and forward average AECO price for 2011 as of November 7, 2011 is $3.52 per GJ. Realized price is equal to total revenue, excluding gas storage revenue, divided by mcf equivalent production.

(2) These are non-GAAP measures; see “Significant accounting policies and non-GAAP measures” in management’s discussion and analysis.

(3) Net debt includes convertible debentures and Senior Notes, both measured at principal amount. Ratios are calculated as ending net bank debt or ending net debt divided by annualized funds flow, estimated based on funds flows for the fourth quarter of 2011.

For 2012, the Corporation is planning a capital program highly focused on its two key commodity diversification priorities; Mannville heavy oil in eastern Alberta and liquids-rich natural gas through horizontal development of the Wilrich formation in the greater Edson area. Capital expenditures will be funded through 2012 funds flow and will be adjusted as commodity prices dictate. Perpetual also has plans for the sale of certain assets in the fourth quarter of 2011 and 2012 for targeted proceeds of $75 to $150 million.

The following table outlines estimated funds flow at various assumed commodity prices:

		AECO Gas Price ($/GJ)				
	Funds Flow ($MM)	**$3.50**	**$4.00**	**$4.50**	**$5.00**	**$5.50**
Edmonton Oil Price ($/bbl)	**$75.00**	48	73	97	121	145
	$85.00	55	79	103	127	151
	$95.00	63	**88**	111	135	159
	$105.00	68	92	116	141	165
	$115.00	73	97	121	145	169
	$125.00	77	102	126	150	174

The sensitivity table above reflects price management activities described in this MD&A and assumes capital expenditures of $70 million, average oil and liquids production of 3,250 bbl/d, natural gas production of 118 MMcf/d, operating costs of $95 million, cash general and administrative expenses of $31 million, an interest rate on bank debt of 5.25 percent and the repayment of the Corporation’s $75 million of 6.5% debentures in cash on June 30, 2012. These assumptions will vary depending on actual commodity prices and capital expenditures.

OTHER NON-GAAP MEASURES

Payout ratio

Payout ratio refers to dividends measured as a percentage of funds flow for the period and is used by management to analyze funds flow available for development and acquisition opportunities as well as overall sustainability of dividends. Funds flow does not have any standardized meaning prescribed by GAAP and therefore payout ratio may not be comparable to the calculation of similar measures for other entities.

Operating and funds flow netbacks

Operating and funds flow netbacks are used by management to analyze margin and funds flow on each Mcfe of oil and natural gas production. Operating and funds flow netbacks do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to the calculation of similar measures for other entities. Operating and funds flow netbacks should not be viewed as an alternative to funds flow from operations, net earnings per common share or other measures of financial performance calculated in accordance with GAAP.

Total capitalization

Total capitalization is equal to net debt including convertible debentures plus market value of issued equity and is used by management to analyze leverage. Total capitalization as presented does not have any standardized meaning prescribed by GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Corporation.

Revenue, including realized gains (losses) on derivatives and total revenue

Revenue, including realized gains (losses) on derivatives, includes call option premiums received and is used by management to calculate the Corporation’s net realized natural gas price taking into account monthly settlements on financial forward natural gas sales and foreign exchange contracts. These contracts are put in place to protect Perpetual’s funds flows from potential volatility in natural gas prices, and as such any related realized gains or losses are considered part of the Corporation’s natural gas price. Total revenue refers to all cash components of production and gas storage revenues, including oil and natural gas sales, realized gains (losses) on derivatives and call option premiums. Total revenue in this MD&A does not include royalties, gas over bitumen revenues or unrealized gains (losses) on derivatives. Revenue, including realized gains (losses) on derivatives and total revenue do not have any standardized meaning as prescribed by GAAP and should not be reviewed as an alternative to Revenue or other measures calculated in accordance with GAAP.

Net debt and net bank debt

Net bank debt is measured as bank debt including net working capital (deficiency) excluding short-derivatives related to the Corporation’s hedging activities, the current portion of convertible debentures, share based payment liabilities and restricted cash. Net debt includes convertible debentures, measured at principal amount. Net bank debt and net debt are used by management to analyze leverage. Net bank debt and net debt do not have any standardized meaning prescribed by Canadian GAAP and therefore these terms may not be comparable with the calculation of similar measures for other entities.

Working capital (deficiency)

Working capital and working capital deficiency are calculated by the Corporation as current assets less current liabilities, excluding assets and liabilities relating to derivatives, share based payments and the current portion of convertible debentures, in order to analyze short-term cash requirements without including mark-to-market balances that may settle for significantly different amounts than those presented on the balance sheet. Working capital (deficiency) as presented does not have any standardized meaning prescribed by GAAP and therefore it may not be comparable with the calculation of working capital (deficiency) for other entities.

INTERNAL CONTROLS

Internal controls have been designed to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements together with the other financial information for external purposes in accordance with GAAP. The Corporation's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision internal controls over financial reporting related to the Corporation, including its consolidated subsidiaries.

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Corporation is accumulated and communicated to the Corporation's management, as appropriate, to allow timely decisions regarding required disclosure. Perpetual’s Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of September 30, 2011 that the Corporation's disclosure controls and procedures are effective to provide reasonable assurance that material information related to Perpetual, including its consolidated subsidiaries, is made known to them by others within those entities. During the three months ended September 30, 2011, there have been no changes in Perpetual’s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Corporation’s internal control over financial reporting.

NEW ACCOUNTING STANDARDS

Transition to IFRS

Effective January 1, 2011, GAAP as accepted in Canada prior to 2011 (“Previous GAAP”) has been conformed to IFRS for publicly accountable enterprises, with a transition date of January 1, 2010. The Corporation’s interim financial statements for the periods ended March 31, 2011, June 30, 2011 and September 30, 2011 were prepared in accordance with IFRS 1 – First-time Adoption of International Financial Reporting Standards and IAS 34, Interim Financial Reporting. Comparative information for 2010 is presented using IFRS unless otherwise noted.

Perpetual's accounting policies are presented in note 3 to the condensed interim consolidated financial statements for the three months ended March 31, 2011, and note 16 to the current period condensed financial statements contains reconciliations between the Corporation's financial position, financial performance and cash flows under IFRS and under Previous GAAP.

In accordance with IFRS 1, Perpetual elected to apply certain exemptions available on first-time adoption of IFRS, as follows.

Business combinations

The Corporation applied the IFRS 1 exemption for business combinations. This allows the Corporation not to restate its previously recorded business combinations incurred under Canadian GAAP before the January 1, 2010 transition date. In applying this exemption the Corporation has reviewed its statements of financial position and operations for any items that would require additional recognition or reclassification namely property, plant, and equipment, intangible E&E assets, leases, and provisions.

Borrowing costs

The Corporation elected to apply IAS 23 borrowing costs and capitalized borrowing costs from an effective date of August 1, 2009. This date coincides with the onset of development of the Warwick natural gas storage reservoir. Borrowing costs associated with this development and subsequent facility construction after August 1, 2009 are capitalized prospectively.

Embedded derivative in convertible debentures

The Corporation has elected to apply the exemption in IFRS 1 not to restate the embedded derivative portion of the convertible debentures no longer outstanding as of January 1, 2010.

Leases

The Corporation elected the exemption in IFRS 1 that allows the Corporation to evaluate any contracts to determine whether in fact they are leases according to circumstances that existed at the transition date. The Corporation's leases were not reassessed to determine whether an arrangement contained a lease under International Financial Reporting Interpretations Committee 4, "Determining whether an Arrangement contains a Lease" for contracts that were already assessed under Canadian GAAP.

Share based payments

IFRS 2 - Share Based Payments has not been applied to equity instruments related to share based compensation arrangements that were granted on or before November 7, 2002, nor has it been applied to equity instruments granted after November 7, 2002 that vested before January 1, 2010. For cash-settled share based payment arrangements, the Corporation has not applied IFRS 2 to liabilities that were settled before January 1, 2010.

Changes in accounting policies

Significant accounting policy differences between IFRS and Previous GAAP relate primarily to property, plant and equipment, decommissioning obligations and derivatives. Specific policy differences are as follows.

Exploration and evaluation ("E&E") assets

Under Previous GAAP, the Corporation followed the successful efforts method of accounting for oil and natural gas operations. Under this method, the Corporation capitalized only those costs that result directly in the discovery of oil and natural gas reserves. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, were charged to net earnings or loss as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, were capitalized. Unproved properties were carried at cost, amortized over the average lease term and tested for impairment annually, with any carrying amount in excess of fair value charged to net earnings or loss. The net cost of unproductive wells, abandoned wells and surrendered leases were charged to net earnings or loss in the year of abandonment or surrender.

In accordance with IFRS 6 – Exploration for and Evaluation of Mineral Resources, the Corporation assessed the classification of activities designated as E&E which then determines the appropriate accounting treatment and classification of the costs incurred.

Property, plant and equipment

The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, remained the same under IFRS as Previous GAAP, adjusted only to segregate E&E expenditures, to adjust asset cost for revised decommissioning obligations and to record gains (losses) on dispositions under IFRS.

Under Previous GAAP, proceeds from dispositions were deducted from the successful efforts cost pool without recognizing a gain or loss unless the deduction resulted in a change to the depletion rate of 20 percent or greater, in which case a gain or loss was recorded.

Under IFRS, gains or losses are recorded on dispositions and are calculated as the difference between the proceeds and the net book value of the assets disposed.

Depletion and depreciation

Under Previous GAAP Perpetual used proved developed reserves as the basis for depleting exploration and development costs, and total proved reserves as the basis for depleting acquisition costs. Under IFRS, the Corporation has elected to use proved plus probable reserves, incorporating future development costs, as the basis for depleting all oil and gas capital costs. As a result, the Corporation's depletion rate per Mcfe of production has decreased compared to previous periods, and D&D expense has also decreased. This change was made effective January 1, 2011.

Decommissioning obligations

Decommissioning obligations (asset retirement obligations) had been measured under Previous GAAP based on the estimated future cost of decommissioning, discounted using a credit-adjusted risk free rate, however under IFRS the liability was required to be re-measured based on changes in estimates including discount rates. The Corporation has chosen a risk free rate as the appropriate discount rate for calculating all decommissioning obligations under IFRS. Perpetual restated the amount of decommissioning obligations as of the IFRS transition date of January 1, 2010 to reflect a risk free interest rate which varied from 1.92 to 4.08 percent over the period of time since the inception of the Corporation. The corresponding increase to the decommissioning liability at the transition date resulted in higher depletion and depreciation expense and lower accretion expense as well as adjustments to the gain on dispositions of property, plant, and equipment in 2010.

Asset and goodwill impairment

Under Previous GAAP, asset impairment is a two-stage test, where the carrying amount of the asset is first compared to the sum of the expected undiscounted future cash flows; if the first test indicates that an impairment exists, then the impairment loss recorded is measured as the difference between the carrying amount and the fair value. Under IFRS, assets are separated into cash-generating units (CGUs), and the greater of value in use and fair value less costs to sell is used both to gauge the likelihood of and record the amount of the impairment. As a result of applying IFRS, the Corporation recorded impairment charges of $24.3 million to its statement of earnings for 2010. Impairment losses can also be reversed under IFRS, which is not permitted under Previous GAAP.

As part of its transition to IFRS, the Corporation elected to restate only those business combinations that occurred on or after January 1, 2010. In respect of acquisitions prior to January 1, 2010, goodwill represents the amount recognized under the Corporation's previous accounting framework. At January 1, 2010, the Corporation carried out an impairment test on its goodwill at the CGU level. The Corporation derecognized $23.1 million of goodwill previously recorded on an acquisition assigned to properties disposed prior to January 1, 2010.

Trust units and convertible debentures

For the first six months of 2010, where Perpetual was an income trust, its Trust Units did not qualify as equity instruments under IFRS guidelines, and were classified as liabilities on the Trust's IFRS statements of financial position dated January 1, 2010 and March 31, 2010. The Trust Units were not considered a derivative and were carried at cost on the statement of financial position under Previous GAAP prior to conversion to a corporation. As a result of this classification, trust unit distributions were recorded as interest expense in Perpetual's statement of earnings for the first six months of 2010. This conclusion also affects the accounting for unit incentive-based compensation and the portion of the convertible debentures that reflect the option to convert the debenture to trust units, both of which were recorded in equity under Previous GAAP but were classified as liabilities for the first six months of 2010, and fair valued every reporting date. Subsequent to Perpetual's conversion to a corporation, common shares outstanding are classified as equity in the Corporation's financial statements.

Share based payments

Prior to the corporate conversion Perpetual had a unit incentive plan ("Unit Incentive Plan"), which was accounted for as a liability-settled award for IFRS due to the trust units being considered liabilities. A liability was recorded on the statement of financial position at January 1, 2010 for the estimated fair value of the rights issued under the plan. The liability was then fair valued every reporting date, with changes in fair value being charged or credited to earnings. Under Previous GAAP, grants under the Unit Incentive Plan were treated as equity-settled awards due to the treatment of trust units as equity.

Upon conversion to a corporation the Unit Incentive Plan was replaced with the Share Option Plan ("Share Option Plan"), and Perpetual implemented a dividend bonus arrangement ("Dividend Bonus Arrangement"), whereby holders of Share Options would, upon exercising the Share Options, receive a cash payment equal to the total dividends declared on the number of Share Options exercised. Under IFRS the Share Option Plan is accounted for as an equity-settled award, and the Dividend Bonus Arrangement is accounted for as a liability-settled award. Both components are fair valued at the grant date, but the dividend bonus portion is re-fair valued every reporting date with changes in value being charged or credited to earnings, while the grant date fair values of the Share Options are expensed over the estimated life of the option. Under Previous GAAP, the Share Option Plan and Dividend Bonus Arrangement were treated as one liability-settled plan, and fair valued every reporting period.

In accordance with IFRS the graded vesting feature of the Share Options and estimated forfeiture rates must be reflected in the grant date fair values, whereas under Previous GAAP grants were fair valued as one tranche and forfeitures were accounted for as they occurred.

Accounting standards issued but not yet adopted

In 2011, the International Accounting Standards Board ("IASB") issued five new standards and an amendment. Five of these items relate to consolidation, while the remaining standard addresses fair value measurement. The new standards are effective for annual periods beginning on or after January 1, 2013. Early adoption is permitted.

IFRS 9, "Financial Instruments" is a result of the first phase of the IASB's project to replace IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

IFRS 10, "Consolidated Financial Statements" replaces IAS 27 "Consolidated Separate Financial Statements". It introduces a new principle-based definition of control, applicable to all investees to determine the scope of consolidation. The standard provides the framework for consolidated financial statements and their preparation based on the principle of control.

IFRS 11 "Joint Arrangements" replaces IAS 31, "Interests in Joint Ventures". IFRS 11 divides joint arrangements into two types, each having its own accounting model. A "joint operation" continues to be accounted for using proportionate consolidation, where a "joint venture" must be accounted for using equity accounting. This differs from IAS 31, which offered the choice to use proportionate consolidation or equity accounting for joint ventures. A "joint operation" is defined as the joint operators having rights to the assets, and obligations for the liabilities, relating to the arrangement. In a "joint venture", the joint venturers have rights to the net assets of the arrangement, typically through their investment in a separate joint venture entity.

IFRS 12 "Disclosure of Interests in Other Entities" is a new standard, which combines all of the disclosure requirements for subsidiaries, associates and joint arrangements, as well as unconsolidated structured entities.

IFRS 13 "Fair Value Measurement" is a new standard meant to clarify the definition of fair value, provide guidance on measuring fair value and improve disclosure requirements related to fair value measurement.

IAS 28 "Investments in Associates and Joint Ventures" has been amended as a result of the issuance of IFRS 11 and the withdrawal of IAS 31. The amended standard sets out the requirements for the application of the equity method when accounting for interest in joint ventures, in addition to interests in associates.

CRITICAL ACCOUNTING ESTIMATES

The MD&A is based on the Corporation's consolidated financial statements which have been prepared in Canadian dollars in accordance with GAAP. The application of GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Perpetual bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

Accounting for petroleum and natural gas operations

The Corporation capitalizes all costs that result directly in the discovery of petroleum and natural gas reserves including acquisitions, successful exploratory wells, development costs and the costs of support equipment and facilities. Geological and geophysical costs, lease rentals and exploratory dry holes are charged to net earnings in the period incurred. Capitalized costs that are exploratory in nature such as undeveloped land acquisitions, oilsands evaluation expenditures and exploration drilling are included in E&E costs, while development and construction costs are included in property, plant and equipment. Costs are transferred from E&E to property, plant and equipment once technical feasibility and commercial viability of the underlying resource have been established. Accounting for petroleum and natural gas operations requires management's judgment to determine the proper designation of wells as either developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results of a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgment to evaluate the fair value of land in a given area.

Reserve estimates

Estimates of the Corporation's reserves included in its consolidated financial statements are prepared in accordance with guidelines established by the Canadian Securities Administrators. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate.

Perpetual's reserve information is based on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be different than these estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition, the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations. The estimates of reserves impact depletion, impairment, dry hole expenses and decommissioning obligations.

Business combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of acquisition of control. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the recognized amount of the net assets acquired, the difference is recognized as a bargain purchase gain in net earnings or loss.

Derivatives

Fair values of derivatives such as forward sales contracts, the gas storage obligation and share based payment liabilities are based on mark-to-market assessments and estimates of fair values, which are subject to management's judgment and measurement uncertainty. Fair values of Share Options are calculated using a binomial lattice option pricing model and involve assumptions such as volatility, expected option life and expected dividend yield.

The Corporation uses estimates to allocate the debenture proceeds from convertible debenture issuances between debt and the derivative debenture liability or equity components, as appropriate.

Impairment of petroleum and natural gas properties

The Corporation reviews its proved properties for impairment on a CGU basis. For each property, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of that property may not be recoverable. The impairment provision is based on the excess of carrying value over the greater of value in use or fair value less costs to sell. Reserve estimates and estimates for natural gas prices and production costs may change and there can be no assurance that impairment provisions will not be required in the future.

Management's assessment of, among other things, the results of exploration activities, commodity price outlooks and planned future development and sales impacts the amount and timing of impairment provisions.

Decommissioning obligations

The decommissioning obligations recorded in the consolidated financial statements are based on the estimated total costs for future site restoration and abandonment of the Corporation's oil and natural gas properties and gas storage facilities, discounted at a risk-free interest rate. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures, the timing of expenditures and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors including changing technology and political and regulatory environments. The appropriate risk-free discount rate is selected based on estimated timing to reclamation and is subject to change as the estimated timelines change. The decommissioning obligations do not include any adjustment for the net salvage value of tangible equipment and facilities.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Perpetual's operations are affected by a number of underlying risks both internal and external to the Corporation. These risks are similar to those affecting others in the conventional oil and gas producers sector. The Corporation's financial position, results of operations and cash available for dividend to Shareholders are directly impacted by these factors.

Gas over bitumen

Recent decisions by the ERCB have brought into question Perpetual's ability to continue to produce natural gas from all of the Wabiskaw and McMurray formations in certain parts of the Athabasca Oil Sands Area in Northeast Alberta. The ERCB and its predecessor the AEUB have ordered shut-ins of some of the Corporation's production and reserves in this area.

The production from the Liege Assets which were shut-in prior to the sale of the property was subject to an interim shut-in decision by the Alberta Energy Resources Conservation Board ("ERCB") announced on May 10, 2011. Perpetual retained operatorship of the Liege Assets in order to be eligible to receive any related gas over bitumen royalty adjustments once the decision was made, and commenced receiving these adjustments on June 1, 2011. There is a risk that other wells in which Perpetual has an interest may be the subject of future shut-in orders.

Contingent and prospective resources

This MD&A contains estimates of "Discovered Bitumen Initially in Place ("DBIIP")", "Undiscovered Bitumen Initially In Place" ("UBIIP"), "contingent resources" and "prospective resources". These terms are not, and should not be confused with, oil and gas reserves. "DBIIP" is defined in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") as that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable. "UBIIP" is defined in the COGE Handbook as that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as prospective resources; the remainder is unrecoverable.

The range of uncertainty of estimated recoverable volumes may be represented by either deterministic scenarios or by a probability distribution. Resources should be provided as low, best, and high estimates as follows:

Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.

Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.

High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.

This approach to describing uncertainty may be applied to reserves, contingent resources, and prospective resources. There may be significant risk that sub-commercial and undiscovered accumulations will not achieve commercial production. However, it is useful to consider and identify the range of potentially recoverable quantities independently of such risk.

"Contingent resources" are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. "Prospective resources" are defined in the COGE Handbook as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. There is no certainty that it will be commercially viable to produce any portion of the resources and that the Corporation will produce any portion of the volumes currently classified as “DBIIP” and "contingent resources". There is no certainty that any portion of the UBIIP and prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources or that the Corporation will produce any portion of the volumes currently classified as “UBIIP” and "prospective resources”.

In general, estimates of gross original resources and recoverable resources are based upon a number of factors and assumptions made as of the date on which the estimates were determined, such as geological, technological and engineering estimates and are subject to a variety of risks and uncertainties and other factors that could cause actual events or results to differ materially from those anticipated in forward-looking estimates. These risks and uncertainties include but are not limited to: (1) the fact that there is no certainty that the zones of interest will exist to the extent estimated or that the zones will be found to have oil with characteristics that meet or exceed the minimum criteria in terms of net pay thickness, porosity or oil saturation, or that the oil will be commercially recoverable to the extent estimated; (2) risks inherent in the heavy oil and oil sands industry; (3) the lack of additional financing to fund the Corporation's exploration activities and continued operations; (4) fluctuations in foreign exchange and interest rates; (5) the number of competitors in the oil and gas industry with greater technical, financial and operations resources and staff; (6) fluctuations in world prices and markets for oil and gas due to domestic, international, political, social, economic and environmental factors beyond the Corporation's control; (7) changes in government regulations affecting oil and gas operations and the high compliance cost with respect to governmental regulations; (8) potential liabilities for pollution or hazards against which the Corporation cannot adequately insure or which the Corporation may elect not to insure; (9) the Corporation's ability to hire and retain qualified employees and consultants; (10) contingencies affecting the classification as reserves versus resources which relate to the following issues as detailed in the COGE Handbook: ownership considerations, drilling requirements, testing requirements, regulatory considerations, infrastructure and market considerations, timing of production and development, and economic requirements; (11) the fact that there is no certainty that any portion of contingent resources will be commercially viable to produce; (12) the fact that there is no certainty that any portion of the prospective resources will be discovered and if discovered, there is no certainty that it will be commercially viable to produce any portion of the resources; and (13) other factors beyond the Corporation's control. In addition, with respect to the disclosed DBIIP and contingent resources at South Liege, there is a significant technical contingency pertaining to the successful implementation of SAGD technology. The successful implementation of SAGD technology in carbonate reservoirs is a significant contingency associated with these assignments that separate them from typical McMurray clastic SAGD contingent and prospective resources, where the technology has repeatedly been proven effective. In addition to this technical contingency, additional contingencies applicable to the Liege South carbonate resource include being in the early evaluation stage (insufficient delineation), economic concerns (not clear whether a future development project would be economic), regulatory issues (environmental and development applications not yet submitted), as well as lack of corporate intent to develop. An economic evaluation was not undertaken with respect to the Corporation's resources and therefore all contingent and prospective resources assigned to the Corporation are currently classified as "economic status undetermined".

Depletion of reserves

Perpetual’s future oil and natural gas reserves and production and therefore its funds flows will be highly dependent on Perpetual’s success in exploiting its reserve base and acquiring additional reserves. Without reserves additions through acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited.

To the extent that external sources of capital including the issuance of additional common shares become limited or unavailable Perpetual's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that Perpetual is required to use funds flow to finance capital expenditures or property acquisitions, the level of dividends will be reduced.

Perpetual reinvests capital to minimize the effects of natural production decline on its asset base. The Corporation currently estimates that capital expenditures of at least $90 million annually are required to maintain production at current levels. There can be no assurance that Perpetual will be successful in developing or acquiring additional reserves on terms that meet the Corporation's investment objectives.

Other risks and uncertainties affecting Perpetual's operations are substantially unchanged from those presented in the Corporation's MD&A for the year ended December 31, 2010.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information and statements within the meaning of applicable securities laws. This information and these statements relate to future events or to our future performance. All statements other than statements of historical fact may be forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook", "guidance", "objective", "plans", "intends", "targeting", "could", "potential", "outlook", "strategy" and any similar expressions are intended to identify forward-looking information and statements.

In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the quantity and recoverability of Perpetual's reserves; the timing and amount of future production; future prices as well as supply and demand for natural gas and oil; the existence, operations and strategy of the commodity price risk management program; the approximate amount of forward sales and hedging to be employed, and the value of financial forward natural gas contracts; funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes; operating, G&A, and other expenses; cash dividends, and the funding and tax treatment thereof; the amount of future abandonment and reclamation costs, asset retirement and environmental obligations; the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Corporation's asset base; expected costs relating to the Corporation's potential gas storage project; the Corporation's acquisition strategy and the existence of acquisition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom; Perpetual's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets; expected book value and related tax value of the Corporation's assets and prospect inventory and estimates of net asset value; ability to fund dividends and exploration and development; our corporate strategy;, expectations regarding Perpetual's access to capital to fund its acquisition, exploration and development activities; the transition to IFRS and its impact on the Corporation's financial results; expected realization of gas over bitumen royalty adjustments; future income tax and its effect on funds flow and dividends; intentions with respect to preservation of tax pools of and taxes payable by the Corporation; funding of and anticipated results from capital expenditure programs; renewal of and borrowing costs associated with the credit facility; future debt levels, financial capacity, liquidity and capital resources; future contractual commitments; drilling, completion, facilities and construction plans; the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other issuers; Crown royalty rates; Perpetual's treatment under governmental regulatory regimes; business strategies and plans of management, including future changes in the structure of business operations; and the reliance on third parties in the industry to develop and expand Perpetual's assets and operations.

The forward-looking information and statements contained in this MD&A reflect several material factors and expectations and assumptions of the Corporation including, without limitation, that Perpetual will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing, and in certain circumstances, the implementation of proposed tax, royalty and regulatory regimes; the ability of Perpetual to obtain equipment, services, and supplies in a timely manner to carry out its activities; the accuracy of the estimates of Perpetual's reserve and resource volumes; the timely receipt of required regulatory approvals; certain commodity price and other cost assumptions; the timing and costs of storage facility and pipeline construction and expansion and the ability to secure adequate product transportation; the continued availability of adequate debt and/or equity financing and funds flow to fund the Corporation's capital and operating requirements as needed; and the extent of Perpetual's liabilities.

Perpetual believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: volatility in market prices for oil and natural gas products; supply and demand regarding Perpetual's products; risks inherent in Perpetual's operations, such as production declines, unexpected results, geological, technical, or drilling and process problems; unanticipated operating events that can reduce production or cause production to be shut-in or delayed; changes in exploration or development plans by Perpetual or by third party operators of Perpetual's properties; reliance on industry partners; uncertainties or inaccuracies associated with estimating reserves volumes; competition for, among other things; capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance; increased costs; incorrect assessments of the value of acquisitions; increased debt levels or debt service requirements; industry conditions including fluctuations in the price of natural gas and related commodities; royalties payable in respect of Perpetual's production; governmental regulation of the oil and gas industry, including environmental regulation; fluctuation in foreign exchange or interest rates; the need to obtain required approvals from regulatory authorities; changes in laws applicable to the Corporation, royalty rates, or other regulatory matters; general economic conditions in Canada, the United States and globally; stock market volatility and market valuations; limited, unfavourable, or a lack of access to capital markets, and certain other risks detailed from time to time in Perpetual's public disclosure documents including, without limitation, those risks and contingencies described above and under ''**Risk Factors**" in the Corporation's MD&A for the year ended December 31, 2010. The foregoing list of risk factors should not be considered exhaustive.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and none of the Corporation or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, unless expressly required to do so by applicable securities laws.

Additional information on Perpetual, including the most recent filed annual report and annual information form, can be accessed from SEDAR at www.sedar.com or from Perpetual's website at perpetualenergyinc.com.