2011 ANNUAL RESULTS

PERPETUAL
ENERGY

TO THE SHAREHOLDERS

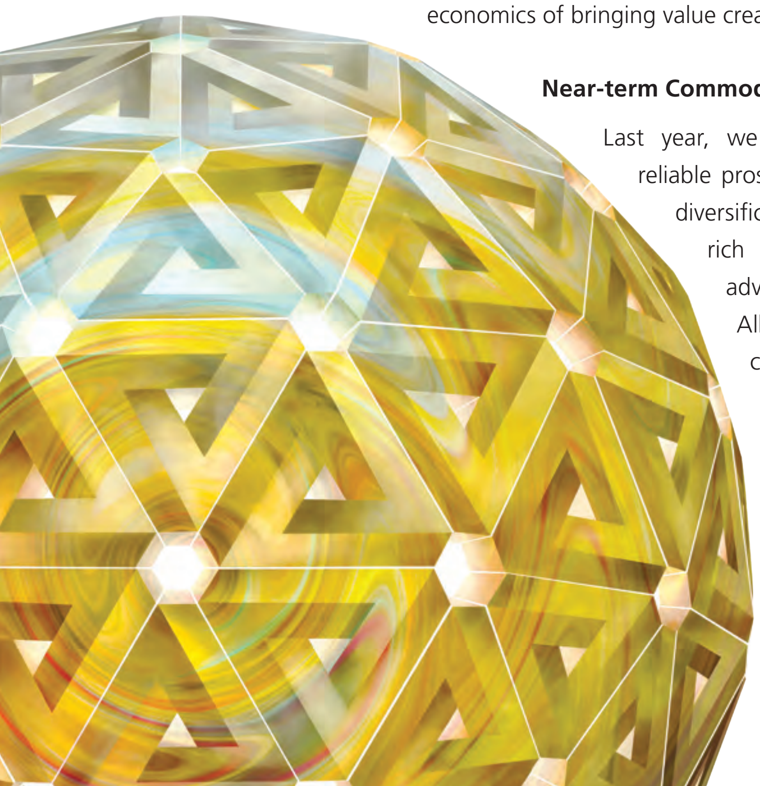
In 2011, Perpetual continued to strategically set in place the key interlocking pieces for a strong future growth story, the same pieces that are now critical to weather the storm of collapsing natural gas prices. We have forged strength from the disciplined execution of our strategy to diversify our asset base and commodity mix. Much has been accomplished to this end. Strict adherence to our business plan is providing resilience and flexibility both operationally and financially given the historic and persistent decline in natural gas.

Supported by funds from our legacy shallow gas assets, we have transformed our asset base from primarily natural gas to a more balanced platform including oil and natural gas liquids (“NGL”or "liquids"), forming the basis for stronger diversified funds flow. Tremendous strides have been taken to prove the economic viability, reliability and scalability of two key diversifying projects where we can bring production on stream quickly; one targeting liquids-rich gas and the other exploiting heavy oil. Furthermore, we continued to advance multiple high-impact plays that will no doubt play leading roles in our longer term growth story; again, a diversified commodity mix, including shallow shale gas, resource-style liquids-rich gas and bitumen. And we have created value through entrepreneurial ideas, such as our gas storage project and several exploration new ventures that are important to strengthen our prospect inventory, funds flow and balance sheet. While the assets will continue to evolve, the foundations of our future as a diversified energy producer are now very much cast.

Bold Ideas for Energy

Like a geodesic dome, we have created an inherently stable structure that is strong for our weight, enclosing a great volume of potential relative to our surface area. Value for shareholders drives all we do and is at the core of the management of our opportunity-rich asset base.

We have transformed our asset base from a pure play in shallow gas into an expansive, balanced portfolio of oil and gas assets and opportunities. Several are near-term value-generators, while other plays have a longer time horizon based on the various stages of evaluation and de-risking of our opportunities. For these longer-term high-impact plays, we are assessing the most feasible technologies and the economics of bringing value creating projects on stream.



Near-term Commodity and Cash Flow Diversification

Last year, we worked to solidify an extensive and reliable prospect inventory for near-term commodity diversification, targeting high impact liquids-rich plays in the Alberta deep basin, and advancing heavy oil opportunities in eastern Alberta that are synergistic with our legacy conventional shallow gas assets. As we achieved excellent success in both these plays, solving the technical formulas for economic returns, we now have robust and repeatable drilling inventories which are ensuring profitability in our capital program.

Perpetual Energy Inc. (“Perpetual”) launched into the Canadian energy industry through the corporate conversion of Paramount Energy Trust, a premium-yielding investment in the royalty trust sector. Formed on June 30, 2010, Perpetual exists to be the energy investment of choice, generating sustainable, premium after-tax returns through finding, exploiting, producing and marketing oil and gas-based energy. Under a strategic plan initiated in 2008, Perpetual has transformed its asset base by capturing diversified resource-style opportunities for near-term development, and is successfully enhancing its commodity mix to include oil and natural gas liquids to balance its legacy of shallow gas properties in eastern Alberta. Furthermore, Perpetual has expansive and diverse opportunities with longer-term high-impact potential in liquids-rich gas, shallow shale gas and extensive bitumen holdings, which are being evaluated with risk-managed investment. The Perpetual team has an entrepreneurial approach focused on being highly profitable and optimizing value at every level. Perpetual has the assets, the people and the vision to build on our legacy – and create our future as a premium energy investment.

BOLD IDEAS
FOR ENERGY

Our operational response to low gas prices was more aggressive drilling directed to higher netback oil and NGL. At mid-2011, as natural gas prices continued to languish and forward markets showed no indication of stronger pricing, we expanded our 2011 capital program to accelerate exploration and development of our most profitable assets; our liquids-rich Wilrich play in Edson, and our conventional heavy oil in the Mannville area of eastern Alberta.

The success of our commodity diversification strategy can be measured in our increased production levels for NGL and oil. Two years ago almost all of our production was natural gas; last year we averaged 2,027 bbl/d of oil and NGL, up from 1,245 bbl/d in 2010 and rising to over 3,300 bbl/d in the last week of December to exit the year. Focused investment increased our year-end weighting to oil and NGL to over 15 percent of production versus eight percent in the fourth quarter of 2010. Highlighting the further decoupling of oil and gas prices, oil and NGL sales generated close to 40 percent of total revenue in the fourth quarter of 2011, up from 20 percent one year ago.

WE HAVE SUCCESSFULLY TRANSFORMED OUR ASSET BASE FROM PRIMARILY NATURAL GAS TO A MORE BALANCED PLATFORM INCLUDING OIL AND NATURAL GAS LIQUIDS.

At the same time, our drilling programs ensured our proved and probable base of reserves remained consistent with last year, declining only one percent, after dispositions and after more than replacing 2011 production. Excluding negative reserve adjustments related entirely to the decrease in natural gas price forecasts, reserves grew five percent year over year. More importantly, the proportion of proved and probable oil and NGL reserves increased to 10 percent, evidence of the growth achievable with a strategic focus on development of the heavy oil and deep basin liquids-rich gas prospects in our inventory.

Those two plays continued to dominate our first quarter 2012 capital program, delivering volume growth in our two key operating areas, but for the rest of the year we are narrowing our operational focus even more. In mid-January as natural gas prices reached a 10-year low, falling below $3.00 per Mcf, we announced further refinement to our 2012 capital program to accelerate our highly profitable Mannville heavy oil activities, while investment in Wilrich drilling has been deferred. While we have identified over 80 net horizontal drilling locations in the greater Edson area providing inventory for several years of high-impact horizontal drilling, in the current climate for gas prices, we believe that shareholder value is best served with superior economic returns on investment in our heavy oil assets.

Focused on Mannville Heavy Oil

In 2012, we will continue to build on our exploration and development successes in the Mannville area in east central Alberta. This area has been a focal point for capital investment with continuous heavy oil drilling since May 2011, which has led to a substantial oil production increase from our Eastern district to 2,600 bbl/d in the first week of March 2012, up from 200 bbl/d just one year ago. Another eight wells are due to be drilled and brought on production before the end of the first quarter. To date, we have delineated 10 pools with heavy oil resource in place in excess of 122 million barrels. Close to 100 locations define our drill ready inventory, with double that captured as prospects at varying levels of delineation and risk. We plan to direct the majority of our capital spending in the remainder of the year to drilling horizontal development and exploration wells on this play to strengthen our base of oil production and its contribution to funds flow, as well as prove up exploratory prospects to further grow the drill ready inventory.

We forecast our oil-focused strategy to result in average 2012 production of 3,600 bbl/d of oil and NGL, assuming capital spending remains within funds flow, and taking into account dispositions of non-core assets. This activity is also expected to increase our oil weighting to more than 20 percent of 2012 exit volumes.

Value Creation with Warwick Gas Storage

Furthering the goal to become a diversified energy company, our Warwick gas storage facility ("WGSI") has been a clear success. Epitomizing our entrepreneurial approach to value creation for our shareholders, in late 2009, Perpetual initiated the development of a partially depleted gas reservoir. WGSI entered its second commercial storage cycle with working gas capacity set at 17 Bcf in April 2011. With withdrawals commencing in January 2011, the facility generated net revenue of $9.0 million in 2011, with an increase to over $11 million expected for 2012, providing a further diversified revenue stream to complement our oil and gas sales. Injection operations are imminent and our forecast for seasonal spreads is promising for the third commercial cycle, once again set at 17 Bcf of working gas capacity. While a successful and innovative new venture, we are currently assessing the value to be gained from divesting a portion or all of the storage facility.

Foundations for Long-term Diversified Growth

While we are sharply focused on near-term commodity diversification, other opportunities offer high-impact, longer term potential. Early in 2011 we assessed several of our bitumen leases through resource evaluation drilling operations. The preliminary analysis of these reservoirs has been encouraging, and we received independent resource assessments primarily covering two properties, Panny and Liege. As a result of our activities, McDaniel recorded a best estimate of 1,157 million barrels of discovered bitumen initially in place and another 2,079 million barrels of undiscovered bitumen initially in place, of which 212 million barrels has been recognized as best estimate contingent resource with another 417 million barrels categorized as prospective resource. Our Panny property is particularly encouraging given the extent of the bitumen resource now confirmed and the fact that the bitumen is capable of flowing at very low rates without any thermal or solvent assistance. As a key priority in 2012, we are continuing to work to unlock the potential of this vast resource through a risk-managed approach to evaluate potentially applicable technologies. To this end, application has been made for a pilot test at Panny to test a novel recovery process which, if successful, will be less capital intensive and more energy and cost efficient than steam-based technologies.

Another longer term opportunity is our liquids-rich Elmworth Montney play which was discovered through grass roots exploration and captured through Crown land purchases to provide material exposure to multiple trillions of cubic feet of natural gas resource. While we are in the early stages of infrastructure and development planning with our 50 percent joint venture partner, this exposure stands to provide flexibility in our phasing of development when natural gas prices strengthen.

Yet another long-term value component is our vast land position for resource-style shallow shale gas in the Viking/Colorado group, overlapping our conventional shallow gas asset base in eastern Alberta. While material spending for further technical evaluation is being curtailed until the natural gas pricing environment improves, we continue to assess development strategies building on the comprehensive technical project initiated in 2010. This play represents a significant mechanism for multiple years of gas development, although its threshold gas price for economic development is not yet fully defined.

Value for shareholders drives all we do and is at the core of the management of our opportunity-rich asset base.

Managing Downside Risk

Our view to a gas price recovery certainly shaped the execution of our strategic priorities in 2011. In March 2011, Perpetual issued $150 million of high yield debt securities to secure flexibility and time to continue our asset base transformation work and further advance our many game-changing opportunities to optimize value. Despite the low gas price environment in 2011, we continued to deliver dividends to shareholders, albeit reduced, up until the final quarter of 2011, attempting to transition our shareholders to a sustainable dividend plus growth model going forward. Although many signs were evident that gas supply would wane and demand would increase, the natural gas supply-demand equation did not rebalance and gas prices continued to decline further through 2011. Finally, with the complete absence of cold weather during this past winter withdrawal season, storage levels for natural gas now stand at record highs and gas prices have entered a state of total collapse, including capitulation of the forward price curve.

In hindsight, our interpretation of the signs for a gas price recovery was clearly too optimistic, and in fact exposed us to downside risk beyond our expectations. In late November, when the possibility of a protracted slump in gas prices became evident to us, we acted quickly to manage our downside risk, hedging gas prices for 2012 and into 2013 at levels that are now significantly above the forward market, but still low relative to historical prices. We also have entered into hedging transactions to protect a base level of revenue from our heavy oil operations as oil revenues are making a material contribution to funds flow. Furthermore, cost reduction initiatives continue to be implemented to improve our bottom line profitability.

With our asset base transformation work well in hand, restoring a healthy balance sheet is now top priority for 2012.

There are currently no strong indicators of renewed short-term natural gas market strength. It remains to be seen when lower funds flows and reduced access to capital for producers will translate into diminished natural gas-directed capital spending and result in a reversal of the robust growth in gas supply we have witnessed since the onset of shale gas development. This reduction in supply will need to align with further demand increases in North America through access to global markets, fuel-switching to gas-fired power generation and increased use of natural gas for transportation, in order to transition fully to the next bull cycle for natural gas.

Restoring a Healthy Balance Sheet

With our asset base transformation work well in hand, restoring a healthy balance sheet is now top priority for 2012. As we have transformed our asset base, opportunities have arisen to high grade our assets to provide additional liquidity, an expected outcome as we evaluated our spectrum of opportunities and narrowed our priorities. Last year we disposed of non-core assets in the West Central and Northern districts for $41.7 million. Then in November 2011 we announced plans to dispose of non-core assets targeting proceeds of $75 to $150 million to be used to strengthen our balance sheet and fund the redemption of Perpetual's $75 million 6.5% convertible debentures, due June 30, 2012, and we are well on track. We have since closed multiple non-core asset dispositions along with a portion of our holdings in TriOil Resources Ltd., which will generate cumulative net proceeds of $66.8 million. These dispositions will have a modest negative impact on funds flow but provide a means to sharpen our focus on our most profitable plays, meet an important financial obligation and strengthen the balance sheet. We are continuing to pursue additional asset sales to meet our targets.

Priorities for 2012

Gas prices may remain low for some time. That factor is out of our control, but we will continue to focus on our top four priorities in 2012:

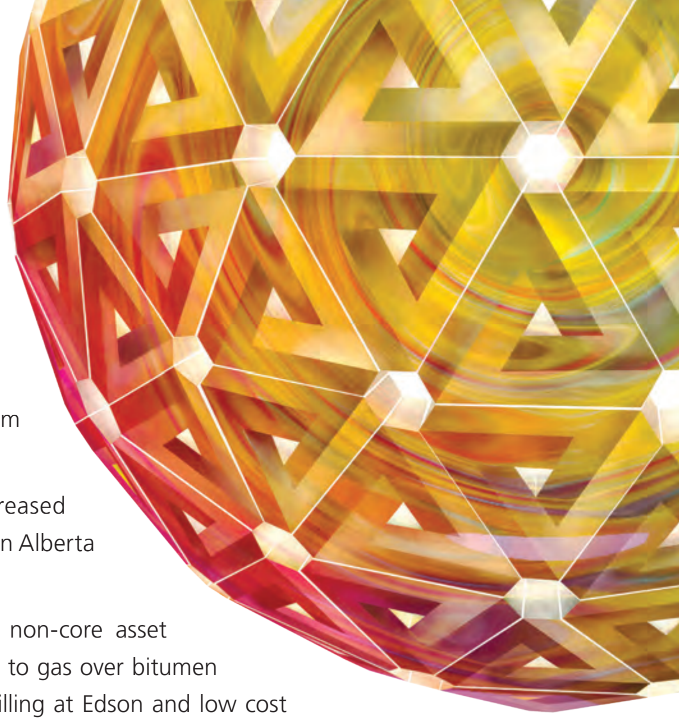
- Restoring a healthy balance sheet;
- Increasing oil and NGL production through focused capital investment in our key diversifying plays to build stronger funds flow;
- Advancing the assessment of longer-term high impact opportunities with risk-managed investment; and
- Managing downside risk.

All of these priorities are critical to navigate our business through this current low gas price environment, and position ourselves for a successful future. We are resolved to build an organization that can prosper despite current low gas prices, and one with tremendous leverage to a gas price recovery.

Although the economic environment has become increasingly challenging, our conviction remains to maximize value for our shareholders, relying on the inherent strength of the interlocking pieces that have been set in place through the innovative ideas, technical skills, resourcefulness and perseverance of our people. For their deep commitment I truly thank the Perpetual team.

SUSAN RIDDELL ROSE

March 15, 2012



2011 YEAR END HIGHLIGHTS

Production and Pricing

- Actual and deemed production averaged 168.7 MMcfe/d, down five percent from 177.4 MMcfe/d in 2010.
- Daily average oil and natural gas liquids (“NGL” or "liquids") production increased 63 percent to 2,027 bbl/d, driven by successful heavy oil drilling at Mannville in eastern Alberta and liquids-rich gas drilling primarily developing the Wilrich formation at Edson.
- Natural gas production decreased 10 percent to 130.2 MMcf/d as a result of non-core asset dispositions, the shut-in of natural gas production at Liege in November 2010 due to gas over bitumen concerns, and natural production declines, partially offset by high-deliverability drilling at Edson and low cost workover and recompletion activities in the Eastern district to mitigate decline rates.
- Average gas prices before derivatives decreased 10 percent to $3.77 per Mcf from $4.17 per Mcf in 2010, in line with an 11 percent decrease in AECO monthly index prices. Natural gas prices, including derivatives, declined to $3.82 per Mcf from $7.10 per Mcf in 2010 due to a $151.5 million reduction in realized gains on hedging contracts.
- Average oil and NGL prices before derivatives increased eight percent to $73.90 per bbl for 2011, primarily as a result of higher reference prices. Perpetual’s price increase was lower than the rise in posted prices due to a high percentage of heavy oil in its oil and NGL production mix. Perpetual received $3.1 million in the fourth quarter of 2011 for the sale of a forward call option for 500 bbl/d of 2013 oil production, boosting the realized oil and NGL price to $78.06 per bbl in 2011.

Financial

- Net bank debt decreased 36 percent to $137.7 million at December 31, 2011 from $214.5 million at year end 2010.
- On March 15, 2011, Perpetual issued $150 million of seven year senior unsecured notes (the “Senior Notes”). The Senior Notes bear interest at 8.75 percent, payable semi-annually, and mature on March 15, 2018.
- Production-related operating costs decreased six percent to $84.3 million ($1.62 per Mcfe), primarily due to lower production levels partially offset by higher costs associated with increased oil volumes. Warwick Gas Storage (“WGSI”) operating costs increased to $5.0 million in 2011, its first full year of operations, from $1.5 million in 2010.
- Funds flow decreased 68 percent to $77.0 million as compared to $237.5 million for 2010. The decrease primarily reflects $151.5 million in realized hedging gains in 2010. Excluding the effect of derivatives, funds flow decreased by $9.0 million due to lower natural gas production and pricing, partially offset by growing oil and liquids production and gas storage revenues.
- Net loss for 2011 was $95.9 million, driven primarily by reduced funds flow and impairment losses related to low natural gas prices.
- Perpetual declared dividends of $28.9 million or $0.195 per Common Share in 2011 as compared to $78.6 million or $0.56 per Common Share in 2010. On October 19, 2011, Perpetual announced that, given the continued weakness in natural gas prices, dividends would be suspended until further notice.

Exploration and Development Capital Activity

- Exploration and development expenditures, excluding land, measured $122.8 million as compared to $101.4 million for 2010. Capital spending was concentrated on exploration and development of liquids-rich natural gas in the West Central district, heavy oil drilling at Mannville in eastern Alberta and evaluation of oil sands leases in northeast Alberta.

- Eastern district expenditures of $65 million were concentrated on the drilling and completion of 29 gross (29.0 net) heavy oil wells at Mannville, facility optimization projects designed to reduce production costs, low-cost shallow gas recompletions to maintain production levels, and evaluation of oil sands leases at Panny and Liege.
- Evaluation drilling and coring expenditures were conducted at several of Perpetual's bitumen leases in northeast Alberta during 2011. The preliminary analysis of these reservoirs has been encouraging, and Perpetual has succeeded in obtaining contingent resource evaluations for the Panny and Liege properties as a result of these initiatives.
- West Central district capital spending totaled $75 million, directed primarily to Cardium drilling in the first quarter of 2011, Wilrich delineation and development, and land expenditures to extend Perpetual's Wilrich operations to West Edson.
- Perpetual drilled 62 gross wells (60.5 net) in 2011 with a 100 percent success rate, as compared to 70 gross (63.9 net) in 2010. Drilling activity included 35 gross (34.0 net) oil wells, 16 gross (15.5 net) natural gas wells, seven gross (7.0 net) oil sands evaluation wells and three gross (3.0 net) wells at the WGSI gas storage facility.
- Land acquisitions totaled $16.5 million in 2011, a $2.6 million increase from 2010. Current year spending was directed primarily towards several exploratory parcels in the West Edson area of west central Alberta as well as expanding Perpetual's land position in Mannville and Elmworth.

Warwick Gas Storage

- Gas storage expenditures decreased to $11.2 million from $57.6 million in 2010, which included construction of the storage facility. 2011 expenditures were primarily directed to the drilling of three horizontal wells designed to increase the working gas capacity in the storage reservoir.
- Working gas capacity was established at 17 Bcf for the second commercial storage cycle, which commenced April 1, 2011. This was reconfirmed for the third cycle expected to begin injection operations in April 2012.
- The WGSI facility generated net revenue of $9.0 million in 2011, based upon working gas from the test cycle and primarily the injection portion of its second operations cycle. Funds flow from operations in 2012 is expected to exceed $11 million, reflecting full-scale operations.

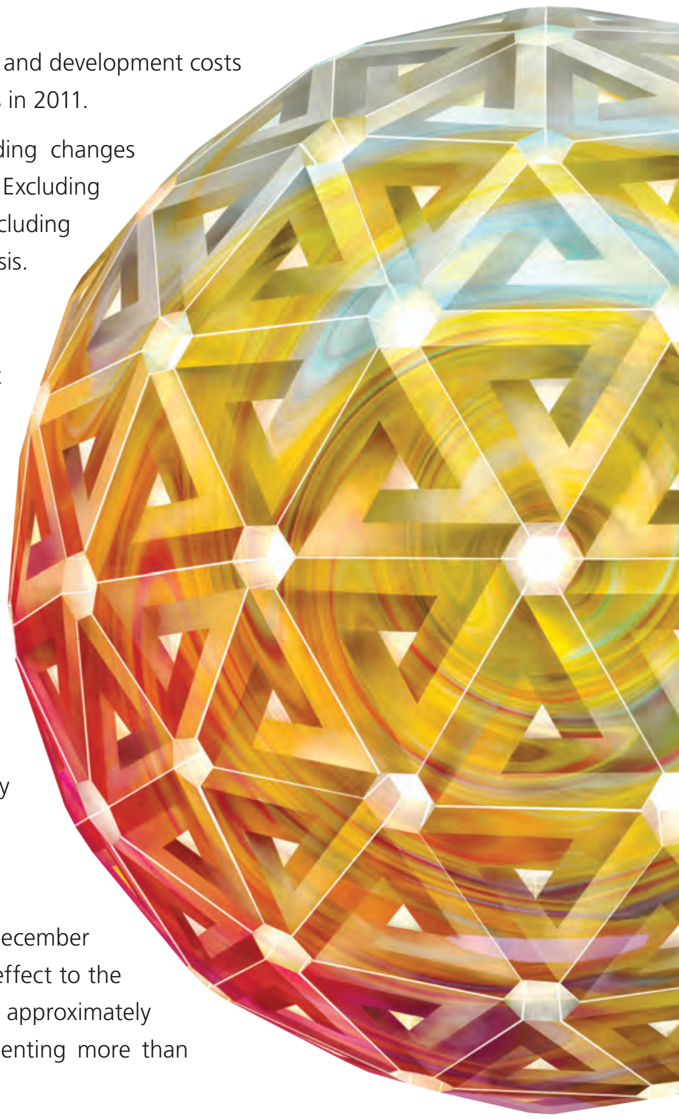
Acquisitions and Dispositions

- Perpetual disposed of non-core assets in the West Central and Northern districts for $41.7 million, providing additional liquidity while high-grading its asset base. The disposed assets are non-core properties located in eastern and west central Alberta and include approximately 6.7 MMcf/d of gas production and oil and NGL production of 115 bbl/d.
- Acquisitions totaling $7.7 million were focused on adding to Perpetual's drilling inventory in greater Edson.

Reserves

- In 2011, Perpetual added 61.1 Bcfe (10.2 MMboe) of proved and probable reserves, excluding production and dispositions. The majority of the reserve additions were driven by Perpetual's asset base transformation and diversification strategy, adding natural gas and liquids reserves in the Alberta deep basin and Mannville heavy oil reserves in eastern Alberta. At year end 2011, oil and NGL represented 10 percent of Perpetual's total proved and probable reserves (12 percent of proved), up from six percent (eight percent of proved) at year end 2010.

- Proved and probable reserves decreased less than one percent to 484.7 Bcfe (80.8 MMboe) at year end 2011, after dispositions of 12.2 Bcfe (2.0 MMboe) and production of 51.9 Bcfe (8.7 MMboe). Before downward revisions related solely to changes in natural gas pricing at year end 2011 of 28.4 Bcfe, Perpetual's reserves grew five percent year over year from 487.7 Bcfe to 513.1 Bcfe.
- Including changes in future development capital ("FDC"), Perpetual realized finding and development costs ("F&D") of $2.86 per Mcfe ($17.16 per BOE) on a proved and probable reserve basis in 2011.
- Perpetual's realized finding, development and acquisition cost ("FD&A"), including changes in FDC, was $2.88 per Mcfe ($17.28 per BOE) on a proved and probable basis. Excluding downward reserve revisions related solely to natural gas price reductions, FD&A including changes in FDC was $1.82 per Mcfe ($10.92 per BOE) on a proved and probable basis.



Bitumen Resource

- McDaniel & Associates Consultants Ltd. ("McDaniel") completed an independent resource assessment of several of Perpetual's oil sands leases and assigned resource estimates primarily for the Bluesky formation in the Panny area, as well as the Grosmont and Leduc carbonate formations at Liege. McDaniel recognized a best estimate of 1,157 MMbbl of Discovered Bitumen Initially In Place ("DBIIP") and a best estimate of 2,079 MMbbl of Undiscovered Bitumen Initially In Place ("UBIIP") in the areas evaluated. The best estimate contingent resource and additional prospective resource recognized are 212 MMbbl and 417 MMbbl respectively. McDaniel's estimates for the Bluesky formation at Panny are based on the potential application of cyclic steam stimulation. In the carbonate reservoirs, bitumen resource was assigned assuming exploitation using Steam Assisted Gravity Drainage ("SAGD") exploitation which is currently considered "technology under development".

OPERATIONS UPDATE

- Perpetual's oil and NGL production averaged 3,316 bbl/d in the last week of December 2011, and is estimated to average over 3,600 bbl/d for calendar year 2012, giving effect to the asset dispositions discussed above and assuming a capital investment program of approximately $65 million. This activity is expected to result in oil and NGL production representing more than 20 percent of 2012 exit production.
- Operational results from Perpetual's asset base diversification strategy continue to be very positive. For 2012, Perpetual has been focused on two key priorities: heavy oil exploration and development in the Mannville area of eastern Alberta and the Wilrich liquids-rich gas play in the greater Edson area. With recent further weakness in natural gas prices, Perpetual's Wilrich drilling has been deferred pending price recovery and all capital is currently being directed to heavy oil drilling at Mannville.

Mannville

- Thus far in the first quarter of 2012, Perpetual has drilled two gross (2.0 net) vertical exploration wells and nine gross (9.0 net) development wells for heavy oil, seven of which have been placed on production. With drilling results exceeding expectations and early production start-up from several of the new well pads, Perpetual's eastern Alberta heavy oil production is ahead of budgeted volumes, exceeding 2,600 bbl/d in the first week of March 2012.

- Perpetual has had a continuous heavy oil drilling program underway since May 2011. This program has resulted in a 13-fold increase in oil production from the Corporation's eastern Alberta operating district, up from 200 bbl/d just one year ago.
- Prior to the end of the first quarter, an additional eight wells will be drilled and placed on production to further increase Perpetual's oil production weighting. Perpetual plans to continue to pursue the economically attractive Mannville heavy oil, directing the vast majority of its remaining 2012 capital spending to this exploration and development program.

Wilrich

- In early January, the Corporation drilled one vertical exploration well and one horizontal development well in the Edson area which are awaiting completion. This brings the number of horizontal Wilrich wells drilled at Edson to 12 gross wells.
- In addition, at West Edson, Perpetual recently completed and tested its second Wilrich horizontal well which was rig released in January 2012. Initial results indicate a second exceptional well, testing at over 15.5 MMcf/d of natural gas at 14 MPa flowing pressure. NGL yields are expected to be 40 bbl per MMcf, consistent with the offsetting discovery well drilled in the fourth quarter of 2011. Tie-in is scheduled for mid-March.
- New facility construction at West Edson is expected to add additional gas and NGL production from the new drill at West Edson, as well as from the horizontal Wilrich discovery well at West Edson which commenced restricted production in December 2011 at 4 MMcf/d (2.0 MMcf/d net). The facility is expected to increase production in West Edson to 12 MMcf/d (6 MMcf/d net) with 480 bbl/d (240 bbl/d net) of NGL recovered through processing at the third party operated Edson deep cut plant.
- Perpetual internally recognizes approximately 80 net future horizontal drilling locations on its lands in the greater Edson area. At year end 2011, 10.1 net future development drilling locations were booked in Perpetual's independent reserve report prepared by McDaniel in the Edson and West Edson areas.
- Due to the current depressed gas price environment, no further operations for the Wilrich play are planned for 2012 as economic returns on investment in the Corporation's heavy oil assets are superior at this time.

CORPORATE ACTIVITY

- In November 2011 Perpetual announced that initiatives were underway for the sale of certain assets in the fourth quarter of 2011 and 2012 targeting proceeds of $75 to $150 million to be used to strengthen the balance sheet and provide for the redemption of Perpetual's $75 million 6.5% convertible debentures on June 30, 2012. In the fourth quarter of 2011, Perpetual closed multiple non-core asset dispositions for net proceeds of $3.8 million.
- Subsequent to the end of 2011, several additional non-core asset dispositions have been closed for net proceeds of $63 million, including the disposition of a portion of the Corporation's common shares of TriOil Resources Ltd. The disposed assets are primarily non-core properties located in eastern and west central Alberta and include approximately 8 MMcf/d of gas production and oil and NGL production of 390 bbl/d. Perpetual is continuing to pursue additional asset sales, including the disposition of all or a portion of its gas storage facility at Warwick, to reach the previously announced targeted proceeds in 2012.

OUTLOOK

2012 OUTLOOK

For 2012, Perpetual is focused on four key strategic priorities:

- Restoring a healthy balance sheet;
- Increasing oil and NGL production through focused capital investment in our key diversifying plays to build stronger funds flow;
- Advancing the assessment of longer-term high impact opportunities with risk-managed investment; and
- Managing downside risk.

Perpetual is nearing completion of a $34 million capital spending program for the first quarter of 2012. Expenditures were directed principally toward the advancement of Perpetual's two key commodity diversifying plays: horizontal development of the Wilrich in greater Edson, and exploration and development of heavy oil at Mannville.

- One vertical and two horizontal (2.3 net) wells were drilled at greater Edson, in addition to facility construction to tie-in new production;
- Two vertical and 17 horizontal (19.0 net) wells will be drilled and tied-in at Mannville, and tie-in operations were completed for one well drilled in 2011.

As gas prices reached levels below $3.00 per Mcf in mid-January, investment in all natural gas projects including the Wilrich program was suspended and funds will be redirected to the highly profitable Mannville heavy oil activities. The Board of Directors has approved a capital spending budget to remain within funds flow for 2012.

FINANCIAL AND OPERATING HIGHLIGHTS

($CDN thousands, except volume and per Common Share amounts)	Three months ended December 31 2011	2010	% change	Year ended December 31 2011	2010	% change
FINANCIAL						
Revenue [(1) (2)]	**63,986**	111,150	(42)	**253,150**	417,093	(39)
Funds flow [(2)]	**15,893**	70,509	(77)	**76,986**	237,470	(68)
Per Common Share [(2) (3)]	**0.11**	0.48	(77)	**0.52**	1.69	(69)
Cash flow provided by operating activities	**9,750**	80,210	(88)	**60,428**	199,882	(70)
Per Common Share [(2) (3)]	**0.07**	0.54	(87)	**0.41**	1.42	(71)
Net loss	**(38,691)**	(28,193)	37	**(95,920)**	(100,719)	(5)
Per Common Share (basic and diluted) [(3)]	**(0.26)**	(0.19)	37	**(0.65)**	(0.72)	(10)
Dividends declared	-	16,273	(100)	**28,865**	78,628	(63)
Per Common Share [(4)]	-	0.11	(100)	**0.195**	0.56	(65)
Payout ratio (%) [(2)]	-	23.1	(100)	**37.2**	33.1	12
Total assets	**1,018,089**	1,027,266	(1)	**1,018,089**	1,027,266	(1)
Net bank debt outstanding [(2) (5)]	**137,689**	214,546	(36)	**137,689**	214,546	(36)
Senior notes, measured at principal amount	**150,000**	-	100	**150,000**	-	100
Convertible debentures, measured at principal amount	**234,897**	234,897	-	**234,897**	234,897	-
Total net debt [(2) (5)]	**522,586**	449,443	16	**522,586**	449,443	16
Shareholders' equity	**81,558**	203,904	(60)	**81,558**	203,904	(60)
Capital expenditures						
Exploration and development	**38,269**	38,158	-	**139,214**	115,202	21
Gas storage	**327**	11,171	(97)	**11,207**	57,587	(80)
Acquisitions, net of dispositions	**(2,746)**	(34,253)	(92)	**(33,953)**	50,958	(166)
Other	**97**	332	(71)	**588**	707	(17)
Net capital expenditures	**35,947**	15,408	133	**117,056**	224,454	(48)
SHARES OUTSTANDING (thousands)						
End of year	**146,966**	148,284	(1)	**146,966**	148,284	(1)
Weighted average – basic	**146,905**	147,742	(1)	**147,694**	140,624	5
Diluted	**146,905**	147,742	(1)	**147,694**	140,624	5
March 1, 2012	**146,990**			**146,990**		
OPERATING						
Production						
Average daily natural gas (MMcf/d) [(6)]	**126.8**	135.9	(7)	**130.2**	145.1	(10)
Average daily oil and natural gas liquids ("NGL") (bbl/d) [(6)]	**2,685**	1,535	75	**2,027**	1,245	63
Average daily (MMcfe/d) [(6)]	**142.9**	145.1	(2)	**142.3**	152.6	(7)
Gas over bitumen deemed production (MMcf/d) [(7)]	**27.4**	24.2	13	**26.4**	24.8	6
Average daily (actual and deemed – MMcfe/d) [(6) (7)]	**170.3**	169.3	1	**168.7**	177.4	(5)
Per Common Share (cubic feet equivalent/d/Common Share) [(3)]	**1.16**	1.15	1	**1.14**	1.26	(10)
Average prices						
Natural gas – before derivatives ($/Mcf) [(8)]	**3.35**	3.87	(13)	**3.77**	4.17	(10)
Natural gas – including derivatives ($/Mcf) [(8)]	**3.31**	7.83	(58)	**3.82**	7.10	(46)
Oil and NGL – before derivatives ($/bbl) [(8)]	**79.16**	75.88	4	**73.90**	68.29	8
Oil and NGL – including derivatives ($/bbl) [(8)]	**91.63**	75.88	21	**78.06**	68.29	14

	Three months ended December 31			Year ended December 31		
	2011	2010	% change	**2011**	2010	% change
RESERVES (Bcfe)						
Company interest – proved (9) (10)	**235.1**	250.4	(6)	**235.1**	250.4	(6)
Company interest–proved and probable (9) (10)	**484.7**	487.7	(1)	**484.7**	487.7	(1)
Per Common Share (Mcfe/Common Share) (12)	**3.30**	3.29	-	**3.30**	3.29	-
Estimated present value before tax ($ millions) (11)						
Proved	**431.6**	581.8	(26)	**431.6**	581.8	(26)
Proved and probable	**722.4**	928.2	(22)	**722.4**	928.2	(22)
LAND (thousands of net acres)						
Total land holdings	**3,313**	3,421	(3)	**3,313**	3,421	(3)
Undeveloped land holdings	**1,849**	1,905	(3)	**1,849**	1,905	(3)
DRILLING (wells drilled gross/net)						
Gas	**5/5.0**	3/2.4	67/108	**16/15.5**	48/44.3	(67)/(65)
Oil	**10/10.0**	3/1.0	233/900	**35/34.0**	14/11.6	150/193
Gas storage	**-/-**	-/-	-/-	**3/3.0**	6/6.0	(50)/(50)
Service	**-/-**	1/1.0	(100)/(100)	**1/1.0**	1/1.0	-/-
Oilsands evaluation	**-/-**	-/-	-/-	**7/7.0**	-/-	100/100
Dry	**-/-**	-/-	-/-	**-/-**	1/1.0	(100)/(100)
Total	**15/15.0**	7/4.4	114/241	**62/60.5**	70/63.9	(11)/(5)
Success rate	**100/100**	100/100	-/-	**100/100**	99/98	1/2

(1) Revenue includes realized gains and losses on derivatives and call option premiums received.

(2) This is a non-GAAP measure; please refer to "Significant accounting policies and non-GAAP measures" included in Management's Discussion and Analysis.

(3) Based on weighted average Common Shares outstanding for the period.

(4) Based on Common Shares outstanding at each dividend payment date.

(5) Net bank debt is measured as at the end of the period and includes net working capital (deficiency), excluding short-term derivative assets and liabilities related to the Corporation's hedging activities, the current portion of convertible debentures, assets and liabilities held for sale and the share based payment liability. Total net debt includes senior notes and convertible debentures, measured at principal amount.

(6) Production amounts are based on the Corporation's interest before deduction of royalties.

(7) Deemed production describes all gas shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the Alberta Energy and Utilities Board ("AEUB"), or through correspondence in relation to an AEUB ID 99-1 application. This deemed production is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen financial solution received monthly from the Alberta Crown as a reduction of other royalties payable. See "Gas over bitumen royalty adjustments" in Management's Discussion and Analysis.

(8) Perpetual's commodity hedging strategy employs both financial forward contracts and physical commodity delivery contracts at fixed prices or price collars.

(9) As evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel") in accordance with National Instrument 51-101. See "Reserves" included in this Management's Discussion and Analysis.

(10) Reserves are presented on a company interest basis, including working interest and royalty interest volumes but before royalty burdens.

(11) Discounted at ten percent using McDaniel's forecast pricing. Reserves at various other discount rates are located in the "Reserves" section of Management's Discussion and Analysis. Estimated present value amounts should not be taken to represent an estimate of fair market value.

(12) Based on Common Shares outstanding at period end.

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 year ended December 31, 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 audited consolidated financial statements and accompanying notes for the years ended December 31, 2011 and 2010. Perpetual's financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, which replaced previously generally accepted accounting principles in Canada ("Previous GAAP") on January 1, 2011 with a transition date of January 1, 2010. Comparative figures for the year ended December 31, 2009 included in this MD&A were prepared in accordance with Previous GAAP. Readers are referred to the Transition to IFRS section of this MD&A, and 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 March 12, 2012.

Mcf equivalent ("Mcfe") and barrel of oil equivalent ("BOE") may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a 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

Perpetual is an oil and natural gas exploration and production company headquartered in Calgary, Alberta. The Corporation has been actively transitioning its asset base from primarily shallow gas production to a diversified, resource-style growth-oriented platform for growth. Perpetual currently has liquids-rich natural gas assets in the Deep Basin of west central Alberta, heavy oil production in eastern Alberta, a natural gas storage facility and oilsands leases in northern Alberta to complement its shallow gas production base.

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 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 and to distributions paid by the Trust prior to the conversion date, as the context may require.

NON-GAAP MEASURES

Funds flow

The Corporation charges exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties and the cost of expired leases to earnings or loss in the period incurred. To make reported funds flow in this MD&A more comparable to industry practice the Corporation reclassifies dry hole costs, geological and geophysical costs and expired leases from operating to investing activities in the funds flow reconciliation.

Management uses cash flow provided by operating activities before changes in non-cash working capital, gas over bitumen royalty adjustments not yet received, settlement of decommissioning obligations and certain exploration and evaluation costs described above ("funds flow"), funds flow per common share and annualized 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 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	Three months ended December 31		Year ended December 31	
($ thousands, except per Common Share amounts)	**2011**	2010	**2011**	2010
Cash flow provided by operating activities	**9,750**	80,210	**60,428**	199,882
Exploration and evaluation costs (1)	**960**	1,483	**3,917**	4,030
Expenditures on decommissioning obligations	**(1,867)**	1,201	**2,514**	4,880
Gas over bitumen royalty adjustments not yet received (received)	**(281)**	1,393	**564**	3,357
Distributions expensed through loss	**-**	-	**-**	40,549
Changes in non-cash operating working capital	**7,331**	(13,778)	**9,563**	(15,228)
Funds flow	**15,893**	70,509	**76,986**	237,470
Funds flow per Common Share (2)	**0.11**	0.48	**0.52**	1.69

(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 and evaluation costs that are added back to funds flow include geological and geophysical expenditures and dry hole costs and are considered by Perpetual to be more closely related to investing activities than operating activities.

(2) Based on weighted average Common Shares outstanding for the period.

Additional non-GAAP measures are discussed elsewhere in this MD&A.

FOURTH QUARTER 2011 RESULTS

Fourth quarter information ($ thousands except as noted)		Three months ended December 31	
	2011	2010	% change
Average daily production volumes			
Natural gas (MMcf/d)	**126.8**	135.9	(7)
Oil & NGL (bbl/d)	**2,685**	1,535	75
Total (MMcfe/d)	**142.9**	145.1	(2)
Actual plus deemed production (MMcfe/d)	**170.3**	169.3	1
Natural gas revenue	**39,093**	48,412	(19)
Oil and NGL revenue	**19,552**	10,711	83
Gas storage revenue	**2,768**	2,595	7
Realized gains (losses) on derivatives	**(550)**	49,432	(101)
Call option premiums received	**3,123**	-	100
Oil and natural gas revenue, after derivatives	**63,986**	111,150	(42)
AECO Monthly Index ($/Mcf)	**3.44**	3.58	(4)
Natural gas price, before derivatives ($/Mcf)	**3.35**	3.87	(13)
Realized natural gas price ($/Mcf)	**3.31**	7.83	(58)
WTI Average Price ($US/bbl)	**89.67**	90.77	(1)
Oil and NGL price, before derivatives ($/bbl)	**79.16**	75.88	4
Realized oil and NGL price ($/bbl)	**91.63**	75.88	21
Royalties	**4,185**	2,727	53
Royalties as a percentage of oil, NGL and natural gas revenues (%)	**7.1**	4.6	54
Operating expenses	**25,393**	20,826	22
Per Mcfe	**1.93**	1.56	24
Cash general and administrative (“G&A”) expenses	**7,918**	9,286	(15)
Per Mcfe	**0.60**	0.70	(14)
Funds flow	**15,893**	70,509	(77)
Per Common Share	**0.11**	0.48	(77)
Cash flow provided by operating activities	**9,750**	80,210	(88)
Per Common Share	**0.07**	0.54	(87)
Net loss	**(38,691)**	(28,193)	37
Per Common Share	**(0.26)**	(0.19)	37
Capital expenditures – exploration and development	**38,269**	38,158	-
Capital expenditures – gas storage	**327**	11,171	(97)

In comparing the three months ended December 31, 2011 with the fourth quarter of 2010:

Capital expenditures

- Exploration and development expenditures were consistent at $38.3 million for the fourth quarter of 2011 compared to $38.2 million for 2010. Perpetual expanded its 2011 capital budget in the second half of 2011 to accelerate the development of its liquids-rich Wilrich assets in west central Alberta and its heavy oil program at Birchwavy. In total nine horizontal and one vertical oil wells and four horizontal Wilrich wells were drilled with a 100 percent success rate. Perpetual also drilled a high-impact exploratory well at West Edson which was completed in January 2012, completed the tie-in of a horizontal Dunvegan development well drilled in the third quarter, and expanded its acreage position in the Mannville heavy oil play.

Production & Pricing

- Oil and NGL production increased 75 percent to 2,685 bbl/d due to successful Wilrich liquids-rich gas and Mannville heavy oil drilling programs in 2011. Natural gas production declined seven percent to 126.8 MMcf/d due to natural declines, non-core asset dispositions, and the shut-in of natural gas production and subsequent sale of assets at Liege in November 2010, partially offset by production additions from Karr and Wilrich drilling activities. Perpetual became eligible to receive the gas over bitumen financial compensation for the Liege assets in June 2011, and therefore total actual plus deemed production increased one percent from the fourth quarter of 2010 to 170.3 MMcfe/d for the current period.
- Natural gas prices before derivatives declined 13 percent to $3.35 per Mcf due to lower AECO Monthly Index prices and the inclusion of 10,000 GJ/d of fixed price physical natural gas sales at $7.75 per GJ for November to December 2010 in the previous quarter's price. Realized gas prices decreased 58 percent to $3.31 per Mcf, as natural gas hedging gains totaled $49.4 million for the three months ended December 31, 2010. In anticipation of a low natural gas price environment in 2011, Perpetual crystallized $37.3 million in gains on derivatives in the fourth quarter of 2010 related to 2011 financial natural gas contracts. Perpetual's oil & NGL price before derivatives increased four percent to $79.16 per bbl from $75.88 per bbl for the comparative period in 2010. Including derivatives, Perpetual realized an average oil and NGL price in the fourth quarter of 2011 of $91.63 per bbl.

Financial

- Funds flow decreased 77 percent to $15.9 million for the current quarter primarily due to lower realized gains on derivatives and higher operating costs. The positive impact of the Corporation's ongoing commodity diversification strategy was reflected in the fourth quarter as an increase in the liquids component of the Corporation's production mix contributed to keeping oil and natural gas revenues relatively flat, despite a decline in total production volumes from quarter to quarter.
- The Corporation's royalty rate of 7.1 percent of revenues was higher than the fourth quarter of 2010, as the prior period amount included $1.5 million in royalty recoveries related to previous years.
- Cash G&A expenses decreased $1.4 million from the fourth quarter of 2010 to $7.9 million for the current period due to lower salaries and consulting fees.
- Operating costs increased $4.6 million to $25.4 million ($1.93 per Mcfe) due to higher costs associated with Mannville oil production, increased power costs at Perpetual's gas storage facility related to the increased working gas capacity and workover charges related primarily to the gas storage wells.
- Net loss totaled $38.7 million for the three months ended December 31, 2011, as compared to $28.2 million for the fourth quarter of 2010. Lower funds flows in the current period were partially offset by reduced depletion and depreciation charges, unrealized gains on derivatives and gains on asset dispositions.

ANNUAL RESULTS

($ millions, except volumes and per Common Share amounts)	**2011**	2010	2009
Cash flow provided by operating activities	**60.4**	199.9	228.4
Cash flow provided by operating activities per Common Share (2)	**0.41**	1.42	1.93
Funds flow (1)	**77.0**	237.5	231.3
Funds flow per Common Share (1) (2)	**0.52**	1.69	1.96
Net earnings (loss)	**(95.9)**	(100.7)	14.4
Dividends	**28.9**	78.6	75.8
Dividends per Common Share (3)	**0.20**	0.56	0.64
Payout ratio (%) (1)	**37.3**	33.1	32.8
Exploration and development expenditures	**139.2**	115.2	57.4
Gas storage expenditures	**11.2**	57.6	10.8
Acquisitions, net of dispositions	**(33.4)**	50.9	103.9
Total capital expenditures	**117.0**	224.4	172.7
Net bank debt outstanding at December 31 (4)	**137.7**	214.5	270.8
Senior notes, measured at principal amount	**150.0**	-	-
Convertible debentures, measured at principal amount	**234.9**	234.9	230.2
Total net debt at December 31 (4)	**522.6**	449.4	501.0
Total net debt per Common Share (4) (6)	**3.56**	3.03	3.97
Daily average production (5)			
Natural gas (MMcf/d)	**130.2**	145.1	153.4
Oil & NGL (bbl/d)	**2,027**	1,245	721
Total (MMcfe/d)	**142.3**	152.6	157.7
Gas over bitumen deemed production	**26.4**	24.8	19.9
Total average daily (actual and deemed)	**168.7**	177.4	177.6
Production per Common Share – actual and deemed (cubic feet equivalent/d/Share) (2)	**1.14**	1.26	1.50

(1) These are non-GAAP measures; please refer to "Significant Accounting Policies and Non-GAAP measures" included in this MD&A.

(2) Based on weighted average Common Shares outstanding for the period.

(3) Based on Common Shares outstanding at each cash dividend date.

(4) Net debt is measured as at the end of the period and includes net working capital (deficiency) excluding short-term financial instrument assets and liabilities related to the Corporation's hedging activities, the current portion of convertible debentures, assets and liabilities held for sale and share option plan liabilities. Total net debt includes senior notes and convertible debentures, measured at the principal amount. Please refer to "Significant accounting policies and non-GAAP measures" included in this MD&A.

(5) Production amounts are based on company interest (working interest and royalties receivable) before royalties payable.

(6) Based on Common Shares outstanding at period end.

Capital expenditures

- Exploration and development capital spending increased to $139.2 million in 2011 from $115.2 million in 2010, as Perpetual acquired land and expanded capital activities on its Wilrich liquids-rich resource play in west central Alberta and increased exploration and development of conventional heavy oil in the Mannville area of eastern Alberta. In total 62 wells were drilled (60.5 net) with a 100 percent success rate, compared to 70 wells (63.9 net) in 2010.
- Evaluation drilling and coring expenditures were conducted on several of Perpetual's bitumen leases in northeast Alberta during 2011. The preliminary analysis of these reservoirs has been encouraging, and the Corporation has succeeded in obtaining contingent resource evaluations for the Liege, South Liege and Panny properties as a result of these initiatives.
- The Corporation disposed of non-core assets in the West Central and Northern districts for $41.7 million, providing additional liquidity while high-grading the Corporation's asset base. Acquisitions of $7.7 million were focused on adding to Perpetual's drilling inventory in Edson.

Financial

- Funds flow decreased 68 percent to $77.0 million in 2011 as compared to $237.5 million for 2010. The decrease was primarily due to a $151.5 million reduction in realized gains on derivatives from year to year. Excluding the effect of derivatives, funds flow decreased by $8.7 million due to lower natural gas production and pricing, partially offset by growing liquids production and gas storage revenues.
- On March 15, 2011 Perpetual issued $150 million of seven-year senior unsecured notes (the "Senior Notes"). The Senior Notes bear interest at 8.75 percent, payable semi-annually, and mature on March 15, 2018.
- Net loss for 2011 decreased five percent to $95.9 million, due to lower depletion and depreciation charges, partially offset by reduced funds flows compared to 2010.

- The Corporation declared dividends of $28.9 million or $0.195 per Common Share in 2011 as compared to $78.6 million or $0.56 per Common Share in 2010. On October 19, 2011 Perpetual announced that, given the continued weakness in natural gas prices, dividends would be suspended until further notice.

Production and reserves

- The Corporation's average gas price before derivatives decreased ten percent to $3.77 per Mcf in 2011 from $4.17 per Mcf in 2010, in line with an 11 percent decrease in AECO monthly index prices. Natural gas prices including derivatives declined to $3.82 per Mcf in 2011 from $7.10 in the prior year due to a $151.5 million reduction in realized gains on derivative contracts. Oil and NGL price before derivatives increased $5.61 per bbl to $73.90 per bbl for 2011 primarily as a result of higher reference prices. The increase in the Corporation's price is not as pronounced as the increase in posted prices due to the increasing percentage of heavy oil in Perpetual's oil and NGL production portfolio. The Corporation received $3.1 million in the fourth quarter of 2011 for the sale of a forward call option on 500 bbl/d of 2013 oil production, boosting the realized oil and NGL price to $78.06 per bbl for the current year.
- Daily average oil and NGL production increased by 782 bbl/d or 63 percent from 2010 levels, driven by successful heavy oil and liquids rich gas drilling during the year. Natural gas production decreased ten percent to 130.2 MMcf/d in 2011 as a result of non-core asset dispositions, the shut-in and sale of natural gas production at Liege in November 2010 due to gas over bitumen concerns and natural production declines, partially offset by high-impact drilling at Edson and low cost workover recompletion activities in the Eastern district to mitigate decline rates.
- In 2011, Perpetual added 61.1 Bcfe (10.2 MMboe) of proved and probable reserves, replacing 118 percent of its production (87 percent on a total proved basis). After dispositions of 12.2 Bcfe (2.0 MMboe) and production of 51.9 Bcfe (8.7 MMboe) in 2011, proved and probable reserves decreased less than one percent from 487.7 Bcfe (81.3 MMboe) at year-end 2010 to 484.7 Bcfe (80.8 MMboe) as at December 31, 2011.
- Including changes in future development capital ("FDC"), Perpetual realized finding and development costs ("F&D") of $2.86 per Mcfe ($17.16 per BOE) on a proved and probable reserve basis in 2011. Perpetual's realized finding, development and acquisition costs ("FD&A"), including changes in FDC, were $2.88 per Mcfe ($17.28 per BOE) on a proved and probable basis. Excluding 28.4 Bcf of downward reserve revisions related solely to natural gas price reductions, FD&A including changes in FDC was $1.82 per Mcfe ($10.92 per BOE) on a proved and probable basis.

OPERATIONS

Properties

In recent years Perpetual has initiated an asset base and commodity diversification strategy to add higher impact, growth oriented, resource-style opportunities to its asset portfolio, primarily in the deep basin of west central Alberta and also through exposure to shallow shale gas, heavy oil and bitumen opportunities in eastern Alberta.

Perpetual has made significant progress in this transition from its legacy asset base of conventional shallow natural gas assets in northeast and east central Alberta to add commodity and play diversification with conventional heavy oil and resource-style liquids rich gas and oil plays in the Alberta deep basin. In the fourth quarter of 2011, approximately 25 percent of production and 35 percent of the year-end reserve values came from Perpetual's resource-style assets in west central Alberta. Also in the fourth quarter, oil and NGL production volumes comprised 11 percent of total production volumes and through focused investment in two key priority plays, Wilrich and Mannville heavy oil, this is expected to grow to 15 to 20 percent of average production volumes in 2012.

Perpetual's producing assets are 100 percent concentrated in Alberta.

Eastern district

The Eastern district is geographically comprised of assets in northeast and east central Alberta. Perpetual's legacy gas producing assets acquired with its spin out from Paramount Resources Ltd. in 2003, complemented with consolidating and operationally synergistic asset acquisitions. Production in this multi-zoned potential area is from over ten different Cretaceous or Devonian aged reservoirs and consists of both conventional and tight unconventional shallow gas reservoirs. The northern part of this district largely overlaps the Athabasca Oil Sands area and the Corporation has also amassed a material inventory of oil sands leases for future development that will require a variety of subsurface recovery technologies.

The vast majority of Perpetual's shallow gas properties feature well established, high working interest production and most are operated by Perpetual. The base shallow gas production profile is predictable due to the lengthy production histories and the large number of independent producing entities in Perpetual's asset base. The large number of wells and facilities means unexpected downtime at any single site does not have a material impact on overall production.

Competitive operating costs and access to markets proximal to the producing properties combine to deliver relatively high field netbacks. Perpetual has an extensive inventory of low cost opportunities for value creation including workovers, uphole recompletions and an inventory of drilling prospects which extends throughout the shallow gas asset base. The Corporation has a history of adding production through relatively modest capital expenditures to offset most of the annual natural production declines. Strategic infrastructure ownership provides additional opportunities to add value through operating synergies and economies of scale.

Northeast – Northeast is comprised primarily of the original assets acquired from Paramount Resources at the inception of the Trust in 2003. Significant areas of production in this core area include Saleski, Woodenhouse, Craigend and Leismer. Production is primarily from the Devonian Grosmont and various overlying Cretaceous formations. The majority of the shut-in gas related to the gas over bitumen issue is in the Wabiskaw-McMurray formation in this area. Production was shut-in in 2003 and 2004 as a result of shut-in orders related to the gas over bitumen regulatory issue. Production at Legend was shut-in on October 31, 2009 as a result of an interim ERCB shut-in order related to a more recent gas over bitumen dispute with oil sands owners in the area. Additional production at Liege was shut in when both Legend and Liege were sold in 2010.

Athabasca – Athabasca includes assets south and west of the Corporation's original spin-out assets in the Northeast area. Production is from multiple stratigraphic horizons including Cretaceous clastic and Devonian carbonate reservoirs. Significant gas producing properties in this core operating area include Calling Lake, Darwin, Marten Hills, Panny, Peter Lake and Wabasca/Hoole.

Bitumen/Heavy Oil – Perpetual has over 336,000 net acres of bitumen rights within the northeast area of the Eastern district, including leases at Liege, Ells, Saleski, Panny, Hoole, Wabasca Lake, Calling Lake and Marten Hills. Certain reservoirs, particularly at Panny and Marten Hills, exhibit potential to achieve production through cold-flow technology whereas others will likely require intensive thermal recovery techniques to develop the bitumen resource.

Perpetual has drilled evaluation wells at Panny, Liege and Hoole to further define the resource potential of its bitumen leaseholdings, and received independent contingent resource reports for all three areas in 2011.

Birchwavy East – Shallow gas production from the Birchwavy East area is primarily from Colony channel reservoirs in the Cretaceous Mannville zone as well as other conventional Mannville sand reservoirs. In addition, unconventional, tight, shallow gas resource play potential in the Viking and Colorado Group extend across these assets. The region has also become the focus of Perpetual's Mannville conventional heavy oil development program, with 29 wells drilled in 2011. The oil quality is consistent with Western Canadian Blend at Hardisty.

Birchwavy West – Warwick, Bruce and Killam areas of central Alberta are the major shallow gas producing properties in this core area. A significant inventory of proved and probable undeveloped reserves in the resource play in the Viking formation is booked in this area. As in Birchwavy East, this area holds significant potential for Viking and Colorado shale gas development in the future.

West Central district

The West Central district comprises a number of deep basin resource-style oil and liquids-rich gas plays developed as part of the Corporation's asset base transition initiated in 2008. Production is established from the Carrot Creek/Edson area and includes light crude oil and liquids-rich gas from the Belly River, Cardium, Second White Specks, Viking, Wilrich, Fahler, Ostracod, Ellerslie, Fernie sand, Rock Creek and Blueridge formations. Liquids-rich natural gas (20 to 40 bbl/MMcf) comes from both vertical wells with multiple commingled Cretaceous and Jurassic aged objectives, and horizontal wells with multi-stage fracture stimulations in the Wilrich, Fahler, Notikewin and Rock Creek formations. The West Central lands host a significant number of vertical multi-zone drilling opportunities as well as multiple years of high-impact horizontal drilling inventory to develop the Wilrich in the greater Edson area. The liquids production provides diversification of commodity price risk.

Elmworth Montney – Through grass roots exploration efforts and successful Crown lands sale purchases, Perpetual acquired material exposure to the Montney liquids-rich gas play developing at Elmworth in west central Alberta. To manage operational and technical risk, Perpetual entered into a joint venture arrangement with an industry partner whereby the partner would fund and operate three wells to evaluate the lands to earn a 50 percent working interest. The farm-in arrangement was completed in January 2011, and as a result Perpetual has a 50 percent interest in 78 sections of land with contingent resource and reserves established for Montney gas development. Several infrastructure options are being evaluated to bring the resource to production.

Warwick Gas Storage Inc. ("WGSI")

In late 2009, Perpetual initiated the development of a partially depleted gas reservoir within the Corporation's existing asset base near Vegreville, Alberta and in close proximity to Alberta gas transmission lines, for commercial gas storage purposes. The first test injection and withdrawal cycle was completed in March 2011. Working gas capacity for the second commercial storage cycle which commenced April 1, 2011 has been established at 17 Bcf.

Production

Production by core area and commodity	**2011**	2010	2009
Gas (MMcf/d)			
Eastern district	**102.5**	126.2	146.7
West Central district	**27.1**	18.2	5.6
Other	**0.5**	0.7	1.0
Total (MMcf/d)	**130.1**	145.1	153.4
Oil & NGL (bbl/d)			
Eastern district	**745**	256	405
West Central district	**1,280**	986	312
Other	**3**	3	4
Total (bbl/d)	**2,028**	1,245	721
Total (MMcfe/d)			
Eastern district	**107.0**	127.8	149.2
West Central district	**34.8**	24.1	7.5
Other	**0.5**	0.7	1.0
Total (MMcfe/d)	**142.3**	152.6	157.7
Deemed natural gas production (MMcf/d)	**26.4**	24.8	19.9
Total plus deemed production (MMcfe/d)	**168.7**	177.4	177.6

Natural gas production volumes decreased ten percent to 130.1 MMcf/d in 2011 from 145.1 MMcf/d in 2010, primarily due to the shut-in and sale of natural gas production at Liege in November 2010 and non-core property dispositions during the year. This was partially offset by the full-year effect of the Edson Acquisition completed on April 1, 2010, and subsequent successful drilling in the Wilrich formation at Edson and other high-impact liquids-rich gas prospects in the West Central district which contributed to production volumes in the fourth quarter of 2011. Current year capital programs targeted oil and NGL production additions, thereby allowing natural gas production to decline in favor of investment to bring higher priced oil and NGLs onstream.

The Liege production which was shut-in 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).

Oil and NGL production volumes increased 783 bbl/d or 63 percent from 2010 levels. Capital spending for the year was concentrated on liquids-rich gas in the Edson area and continued successful development of several heavy oil pools at Mannville in eastern Alberta, which resulted in oil and NGL production exceeding 3,200 bbl/d for December 2011. Oil and NGL volumes were 8.6 percent of Perpetual's total production in 2011, as compared to 4.9 percent in 2010.

Total actual and deemed production decreased five percent to 168.7 MMcfe/d from 177.4 MMcfe/d in 2010, as lower natural gas production was partially offset by higher oil and NGL production and higher deemed natural gas production.

Capital expenditures

Capital expenditures ($ thousands)	**2011**	2010	2009
Exploration and development (1)	**122,761**	101,365	53,463
Crown and freehold land purchases	**16,453**	13,837	3,908
Gas storage	**11,207**	57,587	10,800
Acquisitions	**7,707**	142,210	130,465
Dispositions (2)	**(41,660)**	(91,252)	(26,580)
Other	**588**	707	649
Total capital expenditures	**117,056**	224,454	172,705

(1) Exploration and development expenditures for 2011 include approximately $3.9 million in exploration costs which have been expensed directly on the Corporation's statement of earnings (2010–$4.0 million, 2009–$6.4 million). Exploration costs including geological and geophysical 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 2010 include the receipt of $7.1 million in common shares of Trioil Resources Ltd., a junior oil and gas company focused on the exploration and development of Cardium oil plays in southern Alberta, which were received as partial consideration for the sale of Perpetual's Cochrane property completed in the second quarter of 2010. Since this is a non-cash transaction, those proceeds are not included in the Corporation's statement of cash flows for 2010.

Exploration and development expenditures excluding land measured $122.8 million in 2011 as compared to $101.4 million for 2010. Capital spending was concentrated on exploration and development of liquids-rich natural gas in the West Central district, heavy oil drilling at Birchwavy East and evaluation of the Corporation's oil sands leases in northeast Alberta.

Land acquisitions totaled $16.5 million in 2011, a $2.6 million increase from 2010. Current year spending was directed primarily towards several exploratory parcels in the West Edson area of Alberta as well as expanding Perpetual's land position in Mannville and Elmworth.

West Central

Perpetual drilled a total of ten wells (9.2 net) targeting the Wilrich formation at Edson, with an additional two wells (2.0 net) drilled subsequent to year-end. This drilling included a discovery well in the Wilrich at West Edson, doubling the inventory of prospective future locations. In the greater Edson area, Perpetual has now identified over 40 net horizontal drilling locations in the Wilrich formation for future development.

In addition, Perpetual successfully drilled and completed one vertical and one horizontal (2.0 net) development wells at Karr, targeting liquids-rich gas at 40 bbls per MMcf of NGLs. Both wells came on production in the second half of 2011.

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 29 (29.0 net) Mannville oil wells in 2011, increasing heavy oil production by over 1,000 percent during the year to 2,050 bbl/d for December 2011. Horizontal development of five Lloyd Formation pools and one Sparky pool was evaluated and development is ongoing at an initial horizontal well spacing of 200 metres. An additional ten horizontal development wells are planned for the first quarter of 2012. In addition, further exploratory drilling in the first quarter of 2012 will evaluate several other prospective pools for future development potential.

Bitumen

Perpetual holds over 41,400 hectares (162 net sections) of oil sands leases in the Panny Area of northern Alberta. Throughout 2011, Perpetual has worked with its external reserves consultants McDaniel and Associates Ltd. ("McDaniel") to provide estimates of volumes of discovered bitumen initially in place ("DBIIP"), undiscovered bitumen initially in place ("UDBIIP"), contingent resources and prospective resources for a portion of the Corporation's assets in this area. Three vertical wells and a horizontal well were drilled in the area in the first quarter of 2011, and one existing well was deepened in the fourth quarter to evaluate the reservoir quality and bitumen characteristics of the Bluesky formation and to further define the extent of the bitumen resource and extraction potential. The assignments of DBIIP, UDBIIP, recoverable contingent resource and recoverable prospective resource in the McDaniel Report "Perpetual Energy Inc. Clastic Oil sands Resource Assessment Evaluation of Bitumen and Heavy Oil Resources as of June 30, 2011" and the subsequent update "Evaluation of Discovered Bitumen Initially-in-Place and Contingent Bitumen Resources – Panny Area" effective December 31, 2011 are based on approximately 59 wells in the pools, and on the potential application of cyclic steam stimulation to the Bluesky formation. These reports were prepared pursuant to National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities".

Given the extent of the bitumen resource now confirmed across the Panny acreage, the high quality of the Bluesky formation reservoir recovered in core, and that the viscosity of the bitumen discovered is capable of flowing at low rates without any thermal or solvent assistance, the Corporation is encouraged by the results to date at Panny. Perpetual has plans to further quantify the resource through additional drilling, has initiated a detailed review of applicable technologies, and has applied for a pilot test on its lands.

Perpetual holds over 41,000 hectares (161 net sections) of oil sands leases in the Hoole and Marten Hills Areas of northern Alberta. Throughout 2011, the company has worked with McDaniel to provide estimates of volumes of UDBIIP, DBIIP, contingent resources and prospective resources for a portion of the Company's assets in these areas. Three vertical wells were drilled in the area and 13 km of 2D seismic were acquired in the first quarter of 2011, to evaluate the reservoir quality and bitumen characteristics of the Clearwater and Grand Rapids formations and to further define the extent of the bitumen resource and extraction potential. The assignments of DBIIP, UDBIIP, recoverable contingent resource and recoverable prospective resource in the McDaniel Report "Perpetual Energy Inc. Clastic Oil sands Resource Assessment Evaluation of Bitumen and Heavy Oil Resources as of June 30, 2011" are based on 57 wells in the pools, and on the potential application of cyclic steam stimulation to the Clearwater formation and Steam Assisted Gravity Drainage ("SAGD") to the Grand Rapids formation. The Report was prepared pursuant to National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities".

Perpetual holds 30,720 hectares (120 net sections) of oil sands leases in the Liege area. During the first quarter of 2011, the Company acquired 42 km of 2D seismic and drilled three wells which encountered bitumen-saturated reservoir in the Wabiskaw as well as in the Grosmont A, B and C and Leduc carbonate formations. Each of the three wells encountered three or more stacked zones, with at least one zone having greater than 10 meters of continuous bitumen-saturated reservoir. The assignments of DBIIP, UDBIIP, recoverable contingent resource and recoverable prospective resource in the McDaniel Report "Perpetual Energy Inc. Evaluation of Contingent and Prospective Resources of Grosmont and Leduc Bitumen As of October 31, 2011" are based on 55 wells in the pools and on the potential application of SAGD. The Report was prepared pursuant to National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities".

All of Perpetual's contingent resources currently have an "undetermined" economic status as sub-classification into economic and uneconomic categories has not been evaluated. Contingencies affecting the classification of the resources referred to in the McDaniel Reports referenced in the sections above as reserves include corporate development plans, the need for regulatory approval, and the need to perform an economic study regarding production. There is no certainty that it will be commercially viable to produce any portion of the resources. Please see "Notes Pertaining to the Reporting of Bitumen Contingent Resource" in this MD&A for applicable definitions and risk factors.

The bitumen in place and recoverable resource estimates, prepared in accordance with the COGE Handbook, are as follows:

	Discovered(1)				Undiscovered(1)			
Resource Category	Gross Area (hectares)	Company WI	DBIIP (Mbbl)	Gross Recoverable Contingent Resource (Mbbl) (1)	Gross Area (hectares)	Company WI	UDBIIP (Mbbl)	Gross Recoverable Prospective Resource (Mbbl) (1)
Panny Clastics								
Low Estimate(1)		100%	509,242	50,924				
Best Estimate(1)	5,184	100%	755,009	132,127				
High Estimate(1)		100%	983,040	245,760				
Other Clastics								
Low Estimate(1)		100%	36,467	5,470		100%	71,800	7,719
Best Estimate(1)	610	100%	70,691	14,178	676	100%	82,802	17,604
High Estimate(1)		100%	128,406	33,589		100%	167,274	46,737
Liege Carbonates								
Low Estimate(1)		100%	270,416	0		100%	1,629,912	0
Best Estimate(1)	2,717	100%	331,190	66,238	18,002	100%	1,996,227	399,245
High Estimate(1)		100%	405,623	162,250		100%	2,444,868	977,947
Total All Areas								
Low Estimate(1)		**100%**	**816,125**	**56,394**		**100%**	**1,701,712**	**7,719**
Best Estimate(1)	**8,511**	**100%**	**1,156,890**	**212,543**	**18,678**	**100%**	**2,079,029**	**416,849**
High Estimate(1)		**100%**	**1,517,069**	**441,599**		**100%**	**2,612,143**	**1,024,684**

(1) Contingent and prospective resources have been evaluated by McDaniel using the definitions is as defined in section five of the Canadian Oil and Gas Evaluators Handbook, Volume 1. All volumes are reported before the deduction of royalties payable to others. Contingent resource assignments are in addition to any reserve assignments associated with these assets. Please refer to the detailed definitions contained at the end of this release.

Warwick Gas Storage Inc.

Gas storage expenditures decreased to $11.2 million for 2011 from $57.6 million for the prior year. Prior year costs included construction of the storage facility, whereas 2011 expenditures were primarily directed to the drilling of three horizontal wells designed to increase the working gas capacity in the storage reservoir. Capacity was established at 17 Bcf for the second commercial storage cycle, which commenced April 1, 2011.

Acquisitions and dispositions

Acquisitions decreased from $142.2 million for the year ended December 31, 2010 to $7.7 million for the current period. Acquisitions in 2010 included the purchase of natural gas and liquids production as well as extensive gathering and processing infrastructure and undeveloped lands in a desirable multi-zone part of the Alberta deep basin (the "Edson Acquisition"). Current year acquisitions were focused on expanding the drilling inventory of Wilrich locations in the Edson area.

Dispositions for 2011 included non-core assets located in northeast and west central Alberta for net proceeds of $41.7 million, as compared to $91.3 million in 2010. Total gains on dispositions of property, plant and equipment decreased from $41.8 million in 2010 to $12.0 million for 2011 due to the lower number of dispositions in the current year.

Drilling

Wells drilled	2011 Gross	2011 Net	2010 Gross	2010 Net	2009 Gross	2009 Net
Gas	**16**	**15.5**	48	44.3	46	36.2
Oil	**35**	**34.0**	14	11.6	2	2.0
Oilsands evaluation	**7**	**7.0**	-	-	-	-
Service	**1**	**1.0**	1	1.0	-	-
Gas storage	**3**	**3.0**	6	6.0	4	4.0
Dry	**-**	**-**	1	1.0	-	-
Total	**62**	**60.5**	70	63.9	52	42.2
Success rate (%)	**100**	**100**	99	98	100	100

Perpetual drilled 60.5 net wells in 2011 as compared to 63.9 wells in 2010. Oil and gas drilling activity in 2011 included:

- 29 (29.0 net) Mannville heavy oil wells (including one service well);
- Ten (9.2 net) wells targeting liquids-rich gas in the Wilrich formation at Edson;
- Five (4.8 net) wells in the West Central district to delineate other oil and liquids-rich gas plays;
- Three (3.0 net) wells targeting heavy oil cold-flow production at Panny;
- Five (4.5 net) strategic wells in the Eastern district to maintain land positions and add natural gas volumes at a low cost.

Reserves

Perpetual's complete National Instrument 51-101 ("NI 51-101") reserves disclosure as at December 31, 2011 including underlying assumptions regarding commodity prices, expenses and other factors, and reconciliation of reserves on a net interest basis (working interest less royalties payable) is contained in the Corporation's Annual Information Form for the year ended December 31, 2011.

The reserves data set out below (the "Reserves Data") is based upon an evaluation by McDaniel and Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2011 contained in a report of McDaniel dated February 6, 2012 (the "McDaniel Report"). The Reserves Data summarizes the oil, liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using McDaniel forecast prices and costs. The Reserves Data is presented on a company interest basis, including royalty interests and before royalty burdens. Columns and rows in reserve and net present value tables may not add due to rounding.

Oil and natural gas reserves as at December 31			**2011**			2010			2009
Proved	**Oil & NGL (Mbbl)**	**Gas (MMcf)**	**Total (MMcfe)**	Oil & NGL (Mbbl)	Gas (MMcf)	Total (MMcfe)	Oil & NGL (Mbbl)	Gas (MMcf)	Total (MMcfe)
Developed producing	**2,926**	**161,229**	**178,787**	2,360	187,223	201,380	1,786	192,033	202,757
Developed non-producing	**247**	**17,625**	**19,108**	141	20,786	21,633	81	7,808	8,293
Undeveloped	**1,449**	**28,467**	**37,155**	733	22,990	27,390	384	31,018	33,322
Total proved	**4,621**	**207,321**	**235,050**	3,234	230,999	250,402	2,251	230,859	244,372
Probable Producing, non-producing and undeveloped	**3,435**	**200,725**	**221,336**	2,017	198,030	210,133	1,129	174,626	181,398
Probable shut-in gas over bitumen	**-**	**28,319**	**28,319**	-	27,196	27,196	-	45,806	45,806
Total probable	**3,435**	**229,044**	**249,656**	2,017	225,226	237,329	1,129	220,432	227,204
Total proved & probable	**8,056**	**436,365**	**484,706**	5,252	456,224	487,731	3,380	451,291	471,576
Total proved & probable per Common Share (Mcfe/Share)			**3.30**			3.29			3.74

The proved producing reserves comprise 76 percent of the total proved reserves and 37 percent of the total proved and probable reserves, while proved and probable developed producing reserves are 51 percent of the total proved and probable reserves. Total proved reserves account for 48 percent of the total proved and probable reserves.

The Corporation's total proved & probable natural gas reserves at December 31, 2011 decreased four percent from 2010, as positive technical revisions due to improved production performance in the Eastern district and reserve additions from drilling activity at Edson were more than offset by natural gas production, property dispositions during the year and negative reserve revisions of 28.4 Bcfe due to economic limits, caused by a decrease in McDaniel forecast natural gas prices from year to year.

Proved and probable oil and NGL reserves increased by 53 percent over prior year levels due to the concentration of Perpetual's 2011 capital spending programs on heavy oil and liquids-rich gas development. Perpetual intends to continue to increase liquids reserves as a portion of the Corporation's asset portfolio in 2012 with development capital directed primarily to these assets.

McDaniel's price forecast utilized in the evaluation is summarized below.

McDaniel January 1, 2012 price forecast

Year	West Texas Intermediate Crude Oil ($US/bbl)	Edmonton Light Crude Oil ($Cdn/bbl)	Natural Gas at AECO ($Cdn/MMBtu)	Foreign Exchange ($US/$Cdn)
2012	97.50	99.00	3.50	0.975
2013	97.50	99.00	4.20	0.975
2014	100.00	101.50	4.70	0.975
2015	100.80	102.30	5.10	0.975
2016	101.70	103.20	5.55	0.975
2017	102.70	104.20	5.90	0.975
2018	103.60	105.10	6.25	0.975
2019	104.50	106.00	6.45	0.975
2020	105.40	106.90	6.70	0.975
2021	107.60	109.20	6.85	0.975
2022	109.70	111.30	6.95	0.975
2023	111.90	113.50	7.05	0.975
2024	114.10	115.80	7.20	0.975
2025	116.40	118.10	7.40	0.975
Escalate thereafter at	2%	2%	2%	0.975

Perpetual's proved and probable reserves to production ratio at December 31, 2011, also referred to as reserve life index ("RLI") was 9.7 years while the proved RLI was 5.3 years, based on 2012 production estimates in the McDaniel Report. These represent increases of 11 percent and eight percent, respectively from the RLI at December 31, 2010.

The Net Present Values of future net revenues ("NPV") for Perpetual's reserves, before taxes using McDaniel forecast prices and costs at zero, five and ten percent discount rates are presented in the table below.

NPV of reserves at December 31			**2011**			2010			2009
($ millions)	**0%**	**5%**	**10%**	0%	5%	10%	0%	5%	10%
Proved									
Developed producing	**482.2**	**393.0**	**335.8**	674.3	537.7	453.4	784.3	654.6	569.5
Developed non-producing	**79.6**	**37.8**	**24.0**	99.7	44.4	26.4	17.6	14.0	11.9
Gas over bitumen royalty adjustments	**65.1**	**54.8**	**47.1**	110.6	92.3	78.8	129.9	109.9	94.9
Undeveloped	**77.2**	**42.4**	**24.8**	57.2	36.0	23.2	77.2	56.0	41.1
Total proved	**704.1**	**528.0**	**431.6**	941.8	710.4	581.8	1,009.0	834.5	717.4
Probable									
Developed and undeveloped	**547.5**	**341.2**	**240.6**	652.6	417.0	293.4	727.2	497.4	359.9
Shut-in gas over bitumen reserves (1)	**92.1**	**66.9**	**50.2**	105.9	73.6	53.0	100.3	55.3	32.3
Total probable	**639.6**	**408.1**	**290.8**	758.5	490.6	346.4	827.5	552.7	392.2
Total proved & probable	**1,343.7**	**936.1**	**722.4**	1,700.3	1,201.0	928.2	1,836.5	1,387.2	1,109.6
Common Shares outstanding (millions)	**147.0**	**147.0**	**147.0**	148.3	148.3	148.3	126.2	126.2	126.2
Total proved & probable per Common Share ($/Share)	**9.14**	**6.37**	**4.91**	11.47	8.10	6.26	14.55	10.99	8.79

(1) The McDaniel Report assumes that the shut-in gas over bitumen reserves are probable but the future abandonment and reclamation liability associated with the wells is proved, that the reserves return to production after ten years of shut-in and that such production is subject to an incremental ten percent gross overriding royalty payable to the Crown.

At a ten percent discount factor, the proved producing reserves comprise 46 percent of the total proved and probable value while proved and probable developed producing reserves represent 69 percent of the total proved and probable value. Total proved reserves account for 60 percent of the proved and probable value.

After-tax reserve amounts from the McDaniel Report using forecast prices and costs are shown below.

After-tax net present values as at December 31, 2011	Total proved		Total proved and probable	
($ millions, discounted at 0% and 10%)	0%	10%	0%	10%
Net present value, before taxes	704.1	431.6	1,343.7	722.4
Income taxes	-	-	(133.1)	(50.5)
Net present value, after taxes	**704.1**	**431.6**	**1,210.6**	**671.9**

The McDaniel Report assumes the utilization of Perpetual's current existing tax pools plus additions from future development costs for proved and probable reserves, beginning in 2012 with taxation of after-tax cash flow at corporate income tax rates beginning in 2016. The Corporation has tax pools in excess of the undiscounted value of its proved reserves, and therefore income taxes paid on the production and sale of proved reserves are estimated to be zero.

The following table sets forth a reconciliation of the changes in reserves for the year ended December 31, 2011 from the opening balance on December 31, 2010 derived from the McDaniel Reports at those dates, using McDaniel forecast prices.

Reserves reconciliation (MMcfe)	Proved	Probable	Proved & Probable
December 31, 2010	250,402	237,329	487,731
Discoveries and extensions	43,247	34,966	78,213
Technical revisions	21,632	(10,323)	11,309
Acquisitions, net of dispositions	(8,387)	(3,829)	(12,216)
Production	(51,939)	-	(51,939)
Economic factors	(19,905)	(8,487)	(28,392)
December 31, 2011	**235,050**	**249,656**	**484,706**

Finding and development ("F&D") costs

Under NI 51-101, the methodology to be used to calculate F&D and FD&A costs includes incorporating changes in FDC required to bring the proved undeveloped and probable reserves to production. For continuity, Perpetual has presented herein F&D and FD&A costs calculated both excluding and including FDC. Changes in forecast FDC occur annually as a result of development activities, acquisitions and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production. McDaniel estimated the FDC required to convert proved and probable non-producing and undeveloped reserves to producing reserves at $317.6 million, an increase of $35.4 million from McDaniel's estimate of FDC at December 31, 2010. The increase is primarily due to costs related to additional non-producing reserves booked at Edson, Mannville and Elmworth during the year.

The following table summarizes Perpetual's F&D and FD&A costs, before and after the inclusion of changes in FDC. Finding and development costs, including changes in FDC were $2.86 per Mcfe ($17.16 per BOE) on a proved and probable basis in 2011.

Perpetual has also summarized in the table below these same metrics with the effect of the price-related reserve revisions removed. Perpetual believes that the majority of these reserves will return to the books with a recovery in natural gas prices as the technical merits for booking the reserves have not changed, only the economic circumstances. Excluding the effects of negative reserve revisions related to substantially lower forward gas prices, including changes in FDC, Perpetual's F&D costs were $1.95 per Mcfe ($11.70 per BOE) for proved and probable reserves and FD&A costs were $1.82 per Mcfe ($10.92 per BOE) in 2011 on a proved and probable basis.

2011 F&D and FD&A costs – company interest reserves

($ millions, except as noted)	Proved	Proved Excluding Price Revisions (2)	Proved and Probable	Proved and Probable Excluding Price Revisions (3)
F&D Costs, Excluding FDC				
Exploration and Development Capital Expenditures (1)	$139.2	$139.2	$139.2	$139.2
Reserve Additions Including Revisions – Bcfe	45.0	64.9	61.1	89.5
F&D – $/Mcfe (4)	**$3.09**	**$2.14**	**$2.28**	**$1.56**
F&D Costs, Including FDC				
Exploration and Development Capital Expenditures	$139.2	$139.2	$139.2	$139.2
Total Change in FDC	40.4	40.4	35.4	35.4
Total F&D Capital including Change in FDC	$179.6	$179.6	$174.6	$174.6
Reserve Additions Including Revisions – Bcfe	45.0	64.9	61.1	89.5
F&D Costs – $/Mcfe (4)	**$3.99**	**$2.77**	**$2.86**	**$1.95**
FD&A Costs, Excluding FDC				
Exploration and Development Capital Expenditures	$139.2	$139.2	$139.2	$139.2
Net acquisitions	(34.0)	(34.0)	(34.0)	(34.0)
FD&A Capital Expenditures Including Net Acquisitions	$105.2	$105.2	$105.2	$105.2
Reserve Additions Including Net Acquisitions – Bcfe	36.6	56.5	48.9	77.3
FD&A Costs – $/Mcfe (4)	**$2.87**	**$1.86**	**$2.15**	**$1.36**
FD&A Costs, Including FDC				
FD&A Capital Expenditures Including Net Acquisitions	$105.2	$105.2	$105.2	$105.2
Total Change in FDC	40.4	40.4	35.4	35.4
Total FD&A Capital Including Change in FDC	$145.6	$145.6	$140.6	$140.6
Reserve Additions Including Net Acquisitions – Bcfe	36.6	56.5	48.9	77.3
FD&A Costs Including FDC – $/Mcfe (4)	**$3.98**	**$2.58**	**$2.88**	**$1.82**

(1) $11.1 million of capital associated with WGSI has been excluded, includes $16.5 million of undeveloped land capital.

(2) 19.9 Bcf of proved reserves associated with price related revisions have been added back into the total reserve additions and revisions.

(3) 28.4 Bcf of proved and probable reserves associated with price related revisions have been added back into the total reserve additions and revisions.

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

Land

	2011		2010		2009	
Land inventory	**Net acres**	**Average working interest (%)**	Net acres	Average working interest (%)	Net acres	Average working interest (%)
Developed	**1,464,407**	**67.39**	1,516,366	67.49	1,666,352	68.0
Undeveloped	**1,849,013**	**83.46**	1,905,009	84.09	2,092,637	83.1
Total	**3,313,420**	**75.50**	3,421,375	75.82	3,758,989	75.6

Perpetual's undeveloped net acreage position decreased three percent from 2010 levels due to lease expiries and disposed acreage, partially offset by land purchases in west central Alberta and Mannville. Perpetual has an extensive inventory of undeveloped land relative to its production and reserves base.

The Corporation's undeveloped acreage in the Northeast core area includes approximately 239,000 net acres inside the gas over bitumen area of concern. While development of this acreage is restricted in certain formations, there are numerous other prospective zones in the region. The mineral rights for leases with shut-in production are continued indefinitely under Section 8(1)(h) of the Mines and Minerals Act (Alberta) until resolution of the gas over bitumen issue. Further, Perpetual has in inventory a total of 334,000 net acres of undeveloped oil sands leases.

Perpetual's third party estimate of the fair market value of its undeveloped acreage by region for purposes of the above net asset value calculation is based on recent Crown land sale activity adjusted for tenure and other considerations and is as follows.

Fair value of undeveloped land

Area	Acres	Total value ($ thousands)	$/Acre
North	903,786	34,663	38.35
South	446,867	44,711	100.06
West central	143,751	56,184	390.84
New ventures	20,230	1,921	94.96
Oil sands	334,379	50,770	151.83
Total	**1,849,013**	**188,249**	**101.81**

The eight percent decrease in estimated fair value of undeveloped land to $188 million at December 31, 2011 from $204 million at December 31, 2010 is primarily due to the sale of Cardium acreage during the year and a reduction in the fair value of Perpetual's fee simple acreage in central Alberta, partially offset by an increase in value of the Corporation's oilsands leases.

Net asset value

The following net asset value ("NAV") table shows what is normally referred to as a "produce-out" NAV calculation under which the Corporation's reserves would be produced at McDaniel's forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV represents the fair market value of Perpetual common shares. Actual results will differ materially from the assumptions mandated by NI 51-101, as these do not reflect the full potential value of the Corporation's extensive prospect inventory.

The value of the WGSI facility has been recorded at cost in the NAV calculation below. Construction of the WGSI facility was completed in the fourth quarter of 2010.

Pre-tax net asset value at December 31, 2011		Discounted at		
($ millions except as noted)	Undiscounted	5%	8%	10%
Total proved and probable reserves (1)	1,344	936	795	722
Fair market value of undeveloped land (2)	188	188	188	188
Market value of TriOil Resources Ltd. shares	4	4	4	4
Warwick gas storage (3)	85	85	85	85
Net bank debt (4)	(142)	(142)	(142)	(142)
Convertible debentures	(235)	(235)	(235)	(235)
Senior notes	(150)	(150)	(150)	(150)
Estimate of additional future abandonment and reclamation costs (5)	(121)	(69)	(52)	(43)
Mark to McDaniel's cost of WGSI forward sale obligation (6)	(42)	(35)	(31)	(29)
Net asset value	**932**	**583**	**463**	**401**
Common Shares outstanding (million) – basic	147	147	147	147
Net asset value per Share ($/Common Share)	**6.34**	**3.96**	**3.15**	**2.73**

(1) Reserve values per McDaniel Report as at December 31, 2011.
(2) Third party estimate.
(3) Book value recorded at cost as at December 31, 2011.
(4) Includes bank debt, net of working capital excluding marketable securities, derivative assets and liabilities and share based payment liability
(5) Amounts are net of salvage value and in addition to amounts in the McDaniel Report for future well abandonment costs related to developed reserves. See "Abandonment and reclamation costs".
(6) Value of Perpetual's forward sale obligation related to the gas storage funding arrangement at December 31, 2011 assuming settlement against the McDaniel price forecast.

The above evaluation includes future capital expenditure expectations required to bring undeveloped reserves recognized by McDaniel and GLJ that meet the criteria for booking under NI 51-101 on production. In order to independently assess the "going concern" value of the Corporation, a more detailed independent assessment would be required of the upside potential of specific properties and the ability of the Perpetual team to continue to make value-adding capital expenditures, some of which may require external financing.

Perpetual's three year history of net asset value and net asset value per Common Share, discounted at eight percent and including dividends paid to Shareholders, is as follows.

Pre-tax net asset value at December 31, discounted at 8% ($ millions except per share amounts)	**2011**	2010	2009
Net asset value	**463**	775	830
Net asset value per Common Share ($/Share)	**3.15**	5.23	6.59
Dividends per Common Share ($/Share)	**0.20**	0.56	0.64
Net asset value per Common Share including dividends paid ($/Share)	**3.35**	5.79	7.23

MARKETING

Natural gas prices

Natural gas price ($/Mcf, except percentages)	**2011**	2010	2009
Reference prices			
AECO monthly index	**3.67**	4.13	4.14
AECO daily index	**3.63**	4.00	3.98
Alberta Gas Reference Price (1)	**3.46**	3.77	3.85
Average Perpetual prices			
Before derivatives (2)	**3.77**	4.17	4.12
Percent of AECO Monthly Index	**103**	101	100
Including derivatives ("realized" natural gas price)	**3.82**	7.10	7.09
Percent of AECO Monthly Index	**104**	172	171

(1) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.

(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 financial derivatives.

U.S. natural gas prices are typically referenced to NYMEX at the Henry Hub in Louisiana, while western Canada natural gas prices are referenced to the AECO Hub in Alberta. AECO Monthly Index prices decreased 11 percent from 2010 to 2011, averaging $3.67 per Mcf for the current year. North American natural gas prices have been under downward pressure since 2008 as a result of increased supply from shale gas plays coupled with reduced industrial demand. A lack of weather-related demand in late 2011 continued to push AECO prices downward, resulting in a December AECO monthly index price of $3.05 per Mcf. Perpetual's natural gas price before financial hedging decreased ten percent to $3.77 per Mcf in 2011 from $4.17 per Mcf in 2010, commensurate with the decline in AECO prices. The Corporation's natural gas price exceeds the AECO Monthly Index price due to the inclusion of a physical fixed-price contract for 10,000 GJ/d at a price of $7.75 per GJ in natural gas revenues for January to March 2011.

Perpetual's average realized gas price was $3.82 per Mcf in 2011 compared to $7.10 per Mcf in 2010. Realized gas prices were well above the AECO Monthly Index for 2010 due to realized gains on derivatives of $155.0 million.

Oil and NGL prices

Oil and NGL prices ($/bbl)	**2011**	2010	2009
West Texas Intermediate ("WTI") light oil (US$/bbl)	**94.01**	79.53	61.80
Average Perpetual prices			
Before derivatives	**79.16**	68.29	61.91
Including derivatives ("realized" oil and NGL price)	**91.63**	68.29	61.91

The Corporation's oil and NGL price increased to $79.16 per bbl in 2011 from $68.29 per bbl in 2010, primarily due to higher reference oil prices, partially offset by an increasing proportion of heavy oil production included in Perpetual's liquids production mix. Perpetual's realized price increased to $91.63 per bbl due to the receipt of $3.1 million in 2011 for the sale of a call option on 500 bbl/d of oil at US$105 per bbl for calendar year 2013, measured against the WTI index. Consistent with prior years, cash received for call options sold is included in realized prices and cash flow from operating activities, as well as funds flow.

Risk management

Perpetual's commodity price risk management strategy is focused on using derivative instruments to mitigate the effect of commodity price volatility on funds flow, to lock in attractive economics on capital programs and acquisitions and to take advantage of perceived anomalies in commodity 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 prices. 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, capital programs and debt management, 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 derivative contracts with financially sound, credit-worthy counterparties.

For a complete list of Perpetual's outstanding derivatives as at December 31, 2011, please see note 17 to the annual consolidated financial statements as at and for the year ended December 31, 2011. Financial and physical forward natural gas sales arrangements at the AECO trading hub as at March 7, 2012 are as follows:

Type of contract	Term	Volumes at AECO (GJ/d)(1)	Price ($/GJ)(1)	Futures market ($/GJ)(4)	% of 2012 gas production(2)
Financial – AECO (3)	January – December 2012	45,250	3.72	2.09	35
Financial – NYMEX	March 2012	50,000	2.52	2.45	3
Financial – AECO	March 2012	40,000	2.20	1.97	3
Financial – AECO	April – October 2012	10,000	2.85	1.84	4
Financial – AECO	April – December 2012	19,000	2.60	1.99	11
Physical – AECO	April – December 2012	25,000	2.59	1.99	14
Financial – AECO	January – December 2013	25,000	3.23	2.82	19

(1) Average price calculated using weighted average price for net open sell contracts. NYMEX prices in $US/MMBtu.

(2) Calculated using 2012 estimated gas production of 130,000 GJ/d including gas over bitumen deemed production.

(3) These derivative transactions are part of paired transactions in which the proceeds from the sale of crude oil call options which were used to fund the 2012 natural gas contracts at the price indicated.

(4) Futures market price incorporates settled AECO Monthly Index and NYMEX prices for January to March 2013 and forward AECO prices as of March 7, 2012.

Perpetual also has in place the following costless collar oil sales arrangements, to reduce exposure to fluctuations in the WTI index:

Type of contract	Term	Volumes at WTI (bbl/d)	Floor price ($US/bbl)(1)	Ceiling price ($US/bbl)(1)	Futures market ($US/bbl)(3)	% of 2012 oil production(2)
Collar	January – December 2012	500	82.00	91.00		14
Collar	January – December 2012	500	80.00	89.00		14
Collar	January – December 2012	500	85.00	97.00		14
Collar	January – December 2012	500	90.00	109.25		14
Period total	January – December 2012	2,000	84.25	96.50	103.46	56

(1) Average price calculated using weighted average price for net open contracts.

(2) Calculated using 2012 estimated oil and NGL production of 3,600 bbl/d.

(3) Futures market price incorporates settled and forward WTI oil prices as of March 7, 2012.

The Corporation has entered into two contracts to fix the WTI to oil price differential (WCS differential) on 400 bbl/d at $US17.35 per bbl and on 500 bbl/d at US$28.75 per bbl, both for the 2012 calendar year.

In addition, the Corporation has sold oil call options exercisable and expiring as follows. A premium of $3.1 million was received in the fourth quarter of 2011 for the 2013 call option priced at $105 per bbl, which was included in funds flows for the period.

Type of contract	Term	Expiry	Volumes at WTI (bbl/d)	Strike price ($US WTI)	Futures market ($US WTI)
Call	January – December 2013	Dec 31, 2012	1,000	95.00	105.55
Call	January – December 2013	monthly	1,000	105.00	105.55
Call	January – December 2014	monthly	2,000	105.00	99.65

Perpetual has 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	Term	Perpetual sold/bought	Notional $USD/month	Exchange rate ($CAD/$USD)
Financial	January – December 2012	bought	($1,000,000)	$1.0019
Financial	January – December 2012	bought	($1,000,000)	$1.0085
Financial	January – December 2012	bought	($1,000,000)	$1.0125
Financial	January – December 2012	bought	($2,000,000)	$1.0535

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 March 7, 2012 are as follows:

Type of contract	Term	Perpetual sold/bought	Volume (MWh)	Price ($CAD/MWh)
Financial	January 2012	bought	(7,261.44)	$ 63.77
Financial	February 2012	bought	(5,950.80)	$ 64.13
Financial	March 2012	bought	(5,133.60)	$ 62.58
Financial	January – March 2013	bought	(6,480.00)	$ 76.00

FINANCIAL RESULTS

Revenue

Revenue ($ thousands)	**2011**	2010	2009
Natural gas revenue [(1)]	**179,110**	221,099	229,943
Oil and NGL revenue	**54,674**	31,036	16,300
Gas storage revenue	**14,025**	8,082	-
Realized gains on derivatives [(2)]	**2,217**	155,025	166,340
Call option premiums received	**3,123**	1,851	5,740
Total revenue	**253,149**	417,093	418,323

(1) Includes revenues related to physical forward sales contracts which settled during the period.

(2) Realized gains on derivatives include settled financial forward contracts and options.

Natural gas revenue decreased to $179.1 million in 2011 from $221.1 million in 2010 due to lower gas prices and a ten percent decrease in production volumes, while oil and NGL revenues increased by $23.6 million as a result of higher production and pricing compared to the prior year. Realized gains on derivatives totaled $2.2 million in 2011 as compared to $155.0 million for 2010. Perpetual had anticipated a low 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 the majority of capital spending programs for the first quarter of 2011, leading to the lower realized gains in the current year.

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. Storage revenue increased to $14.0 million for 2011 from $8.1 million for 2010 as withdrawals were not initiated until January 2011. The capacity of the facility was increased to 17 Bcf for the second storage cycle which commenced on April 1, 2011.

The Corporation also recorded unrealized losses on derivatives of $9.4 million in 2011, reflecting the change in the fair value of financial and physical forward commodity contracts during the year.

Funds flow

	2011		2010		2009	
Funds flow reconciliation	**$ millions**	**($/Mcfe)**	$ millions	($/Mcfe)	$ millions	($/Mcfe)
Production volume (Bcfe)	**52.0**		55.7		57.5	
Revenue [(1)]	**253.1**	**4.87**	417.1	7.49	418.3	7.27
Royalties	**(20.6)**	**(0.40)**	(22.1)	(0.40)	(17.4)	(0.30)
Operating costs [(2)]	**(89.3)**	**(1.72)**	(91.2)	(1.64)	(105.1)	(1.83)
Transportation costs	**(10.3)**	**(0.20)**	(11.9)	(0.21)	(11.7)	(0.20)
Operating netback from production	**132.9**	**2.55**	291.9	5.24	284.1	4.94
Gas over bitumen royalty adjustments	**11.5**	**0.22**	12.3	0.22	10.4	0.18
Exploration and evaluation [(3)]	**(3.9)**	**(0.07)**	(4.4)	(0.08)	(4.2)	(0.07)
General and administrative [(3)]	**(30.1)**	**(0.58)**	(34.4)	(0.62)	(32.1)	(0.56)
Interest on debt	**(6.6)**	**(0.13)**	(11.9)	(0.21)	(11.9)	(0.21)
Interest on senior notes [(3)]	**(10.5)**	**(0.20)**	-	-	-	-
Interest on convertible debentures [(3)]	**(16.3)**	**(0.31)**	(16.3)	(0.29)	(15.0)	(0.26)
Funds flow [(3)] [(4)]	**77.0**	**1.48**	237.5	4.26	231.3	4.02

(1) Revenue includes realized gains and losses on derivatives, call option premiums received and gas storage revenue.

(2) Operating costs included $5.0 million ($0.10 per Mcfe) related to the operation of the WGSI Facility.

(3) Excludes non-cash items.

(4) This is a non-GAAP measure; see "Other non-GAAP measures" in this MD&A.

Royalties

Perpetual pays Crown, freehold and gross overriding royalties which are dependent upon production volumes, commodity prices, location and age of producing wells and type of production. Gas Crown royalties are reduced by Gas Cost Allowance ("GCA") deductions, which are based on processing fees and allowable capital costs incurred at a property and are in accordance with Crown royalty regulations. Crown royalty rates tend to decrease with decreases in the Alberta Gas Reference Price, and rise as the reference price increases. Oil royalties are taken in kind directly from the wellhead by the Alberta Crown, and an amount is calculated based on the oil price received by the Corporation and included in royalties expense.

The average royalty rate on oil, NGL and natural gas revenues before derivatives was consistent at 8.8 percent for both 2010 and 2011. Higher natural gas royalties caused by lower gas cost allowance credits were offset by lower oil royalties, as the majority of Perpetual's oil production in 2011 is from new drills that qualify for a five percent royalty for the first year of production.

Operating costs

	2011		2010	
Operating costs	**$ thousands**	**($/Mcfe)**	$ thousands	($/Mcfe)
Production-related operating costs	**84,328**	**1.62**	89,702	1.61
WGSI operating costs	**4,994**	**0.10**	1,459	0.03
Total operating costs	**89,322**	**1.72**	91,161	1.64

Operating costs include all costs associated with the production of oil and natural gas from the wellhead to the point at which the product enters a sales pipeline for transport to market. Field gathering and processing costs are also included in operating costs. Revenue received from the processing of third party production at Perpetual's facilities is netted against operating costs.

Production-related operating costs decreased six percent to $84.3 million ($1.62 per Mcfe) in 2010 as compared to $89.7 million ($1.61 per Mcfe) in 2010, primarily due to lower production levels partially offset by higher workover charges. WGSI operating costs increased in 2011 as it was the first full year of operations for the WGSI facility. Gas injection first commenced on May 1, 2010. The largest component of WGSI operating costs is power charges, primarily required over the winter months when gas is being withdrawn, and as such Perpetual has entered into fixed-price power purchase contracts to manage these costs. Over the past few years Perpetual has implemented cost reduction initiatives at all operated fields to enhance competitiveness and efficiency.

Transportation costs

Costs to transport gas from the plant gate to the commercial market sales point are not reflected as an operating cost but rather are separately recorded as transportation costs for the product. Alberta's gas transportation system operates on a postage stamp basis. Total transportation costs decreased to $10.3 million in 2011 from $11.9 million in 2010, consistent with the decrease in natural gas production levels from year to year. On a unit-of-production basis, transportation costs decreased to $0.20 per Mcfe compared to $0.21 per Mcfe in 2010.

Operating netbacks

Perpetual's operating netback decreased by $159.0 million to $132.9 million for the year ended December 31, 2011 from $291.9 million for the prior year, due primarily to lower realized gains on derivatives, reduced gas production and gas prices, partially offset by increasing oil production and gas storage revenues.

Operating netback reconciliation ($ millions)	
Natural gas price decrease before derivatives	(21.4)
Natural gas production decrease	(20.6)
Oil and NGL price increase before derivatives	2.6
Oil and NGL production increase	21.1
Decrease in gains on derivatives	(151.5)
Gas storage revenue increase	5.9
Royalty expense decrease	1.5
Operating cost decrease	1.8
Transportation cost decrease	1.6
Decrease in operating netback	(159.0)

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))

Through this formula, operating costs are effectively deemed to be $0.40 per Mcf, royalties are deemed to be 20 percent, the deemed production is assigned the Alberta Gas Reference Price, which includes a transportation component and the entire formula is assigned a 50 percent reduction factor. The deemed production volumes is reduced by ten percent annually. The components of netbacks for the gas over bitumen shut-in reserves are outlined below.

Gas over bitumen royalty adjustment netback ($ per Mcf)	**2011**	2010	2009
Average deemed volume (MMcf/d)	**26.4**	24.8	19.9
Gas price	**3.46**	3.77	3.85
Royalties	**(0.70)**	(0.75)	(0.77)
Operating costs	**(0.40)**	(0.40)	(0.40)
50% reduction factor	**(1.18)**	(1.31)	(1.34)
Gas over bitumen royalty adjustment netback	**1.18**	1.31	1.34

The Corporation's net deemed production volume for purposes of the royalty adjustment was 26.4 MMcf/d for 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 by 1.6 MMcf/d from the 24.8 MMcf/d recorded for 2010 as a result of royalty adjustments for the shut in volumes at Liege, which the Corporation began receiving in June 2011, partially offset by the annual ten percent reduction in deemed production volumes discussed previously.

A significant portion of royalty adjustments received have been recorded on Perpetual's statement of financial position 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 the 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 these dispositions, the gas over bitumen royalty adjustments received by the Corporation for the affected wells are 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 low gas prices the Corporation's net Crown royalty expenses were 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. All royalty adjustments, whether or not they have been recovered, have been included in funds flow in the periods in which they appeared on the natural gas royalty invoices. Eventual realization of the royalty adjustments is highly likely as deemed production is reduced by ten percent annually, whereas the Corporation is focused on maintaining production and reserves year over year through capital spending programs, complemented with strategic acquisitions. As of December 31, 2011, the Corporation has accumulated $9.0 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:

Gas over bitumen royalty obligation	($ thousands)
Balance, January 1, 2010	77,167
Royalty adjustments	10,454
Royalty adjustments on dispositions	(13,767)
Royalty adjustments not yet received	(3,357)
Balance, December 31, 2010	70,497
Royalty adjustments	4,772
Royalty adjustments not yet received	(564)
Balance, December 31, 2011	**74,705**

Exploration and evaluation

($ thousands)	**2011**	2010	2009
Lease rentals	**3,879**	4,439	4,147
Seismic expenditures and dry hole costs	**3,917**	4,030	6,402
Lease expiries	**8,201**	9,824	11,289
Total exploration and evaluation	**15,997**	18,293	21,838

Exploration and evaluation ("E&E") costs include lease rentals on undeveloped acreage, seismic expenditures, exploratory dry hole costs and lease expiries. E&E costs decreased from $18.3 million in 2010 to $16.0 million in 2011 due to lower lease rental charges and lease expiries, consistent with the reduction in undeveloped land from year to year.

General and administrative expenses

		2011		2010		2009
	$ thousands	**$/Mcfe**	$ thousands	$/Mcfe	$ thousands	$/Mcfe
Cash general & administrative	**30,094**	**0.58**	34,380	0.62	32,134	0.56
Share-based compensation (1)	**5,618**	**0.11**	5,283	0.09	7,481	0.13
Total general & administrative	**35,712**	**0.69**	39,663	0.71	39,615	0.69

(1) Non-cash item

General and administrative expenses ("G&A") include costs incurred by Perpetual which are not directly associated with the production of oil and natural gas. The largest components of G&A expenses are office staff compensation costs and information technology costs. Field employee compensation costs are charged to operating expenses. Overhead recoveries resulting from the allocation of administrative costs to producing properties and capital projects are recorded as a reduction of G&A expenses, and are a function of capital and operating expenditures during the year, as well as the Corporation's productive well base.

Cash G&A expenses, net of overhead recoveries on operated properties, decreased 12 percent to $30.1 million in 2011 from $34.4 million in 2010. The decrease is primarily due to reductions in the employee count and related salaries and consulting fees. Cash G&A in 2010 also included approximately $1.5 million in costs associated with the conversion from an income trust to a corporation. Cash G&A expenses decreased on a unit-of-production basis from $0.62 per Mcfe in 2010 to $0.58 per Mcfe in 2011.

Share-based compensation increased six percent in 2011 from 2010 levels, as higher restricted rights expense caused by an increase in rights granted was partially offset by lower share option expense due to a lower estimated fair value of share options granted. Fair values of share options are a function of the trading price of Perpetual's Common Shares.

Financing expenses

Interest expense on the 8.75% Senior Notes issued on March 15, 2011 totaled $10.9 million for the current year, of which $0.4 million relates to amortization of debt issue costs.

Interest on bank debt decreased to $6.6 million in 2011 from $12.2 million in 2010 as a result lower bank debt balances due to the issuance of Senior Notes during the year.

Interest on convertible debentures increased to $19.9 million in 2011 from $19.5 million in 2010, due to a full year of non-cash amortization of issue costs and accretion of the equity component of the 7.0% convertible debentures issued in May 2010. The cash component of interest on convertible debentures was unchanged at $16.3 million for both periods, as additional interest in 2011 on the 7.0% debentures was matched by interest expense recorded in 2010 on a series of 6.25% convertible debentures that matured on June 30, 2010.

Funds flow

Lower realized gains on derivatives were the primary factor in a decrease of 65 percent in the Corporation's funds flow netback from $4.26 per Mcfe in 2010 to $1.48 per Mcfe in 2011. Funds flow decreased by $160.5 million to $77.0 million ($0.52 per Common Share) for the year ended December 31, 2011 from $237.5 million ($1.69 per Common Share) in the 2010 period.

Depletion, depreciation and impairment

Depletion and depreciation ("D&D") expense decreased from $225.0 million ($4.05 per Mcfe) in 2010 to $116.1 million ($2.23 per Mcfe) in 2011. 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. The Corporation revised its estimate of the D&D rate of its oil and gas properties on January 1, 2011 to include probable reserves and associated future development and decommissioning costs. The effect of this change reduced D&D expense by $117.1 million compared to depletion and depreciation expense calculated in accordance with GAAP for the year ended December 31, 2010. Perpetual believes that proved and probable reserves are a better reflection of the useful life of the Corporation's assets.

At year-end 2011, capital assets included $111.6 million (2010–$107.5 million) of E&E assets (of which $4.8 million was included in assets held for sale), consisting of undeveloped land and oilsands expenditures, not subject to depletion and $23.8 million (2010–$23.8 million) of costs related to shut-in gas over bitumen reserves which are not being depleted due to the non-producing status of the wells in the affected properties. The increase in E&E assets during the year is driven by $25.8 million in expenditures on undeveloped land and oilsands evaluation, partially offset by lease expiries, sales of undeveloped land and transfers of land to developed PP&E.

At the end of each reporting period, Perpetual assesses its oil and natural gas properties, exploration and evaluation assets and gas storage facility for potential indicators of impairment. At December 31, 2011 indicators of potential impairment were identified and Perpetual measured the carrying values of each of its CGUs, less the corresponding decommissioning obligations, against the estimated value in use. An impairment loss of $25.6 million was recorded for 2011 (2010–$24.3 million) as a result of this analysis.

Assets held for sale

As part of Perpetual's non-core disposition program, the Corporation has identified $20.3 million of oil and gas assets that were held for sale as of December 31, 2011. The assets held for sale do not represent a total amount of estimated dispositions in 2012, but are the potential dispositions that were deemed "highly probable" as of the reporting date. These properties were located primarily in the West Central and South districts, and the related dispositions were closed in the first quarter of 2012. Subsequent to year-end, Perpetual identified the WGSI Facility as an asset held for sale.

Decommissioning obligation

Perpetual estimates its total future decommissioning obligation based on net ownership interest in all wells, facilities and pipelines, including estimated costs to abandon the wells, facilities and pipelines and reclaim the sites and the estimated timing of the costs to be incurred in future periods. Pursuant to this evaluation, the estimated undiscounted total value of Perpetual's future decommissioning obligation is $326 million as at December 31, 2011. As at December 31, 2011, the undiscounted net salvage value of the Corporation's gas plants, compressors and facilities was estimated at $151 million. The McDaniel Report includes an undiscounted amount of $81 million with respect to expected future well abandonment costs related specifically to proved and probable reserves and such amount is included in the values captioned "Total proved and probable reserves" in the "NPV of reserves" table in this MD&A. The following table presents the estimated future abandonment and reclamation costs and estimated net salvage values at various discount rates.

Abandonment and reclamation costs

		Discounted at		
($ millions, net to Perpetual)	Undiscounted	5%	8%	10%
Well abandonment costs for developed reserves included in McDaniel Report	55	32	25	21
Well abandonment costs for undeveloped reserves included in McDaniel Report	26	14	10	8
Well abandonment costs for total proved and probable reserves included in McDaniel Report	81	46	35	30
Estimate of other abandonment and reclamation costs not included in McDaniel Report	246	141	107	90
Total estimated future abandonment and reclamation costs	**326**	**188**	**142**	**120**
Salvage value	(151)	(87)	(66)	(55)
Abandonment and reclamation costs, net of salvage	**175**	**101**	**76**	**64**
Well abandonment costs for developed reserves included in McDaniel Report	(55)	(32)	(25)	(21)
Estimate of additional future abandonment and reclamation costs, net of salvage (1)	**121**	**69**	**52**	**43**

(1) Future abandonment and reclamation costs not included in the McDaniel Report, net of salvage value.

The decommissioning obligation presented in Perpetual's consolidated financial statements is discounted using an estimate of the timing of asset retirement expenditures and an average risk-free interest rate of 2.6 percent, which is based on Bank of Canada bond rates and reviewed at every reporting date. These expenditures are currently expected to occur over the next 25 years with the majority of costs incurred between 2015 and 2020. Perpetual's discounted decommissioning obligation increased from $236.2 million at December 31, 2010 to $247.7 million at December 31, 2011 primarily due to lower discount rates. Decommissioning obligations of $4.8 million related to assets held for sale were reclassified to current liabilities at December 31, 2011.

Income taxes

Perpetual recorded deferred tax expense of $1.6 million for 2011 (2010–$2.1 million), related to timing differences between book and tax values of the Corporation's gas storage assets. The tax values of the Corporation's non-gas storage assets currently exceed the related book values. Deferred income tax is a non-cash item and does not affect the Corporation's funds flows or its cash position.

Tax pools

Tax pool information ($ millions)	As at December 31, 2011
Canadian oil and gas property expense (COGPE)	298
Canadian development expense (CDE)	161
Canadian exploration expense (CEE)	55
Undepreciated capital cost (UCC)	205
Share issue costs	3
Non-capital losses	166
Total	**888**

At December 31, 2011, the Corporation's consolidated income tax deductions are estimated to be $888 million. Actual tax deduction amounts will vary as tax returns are finalized and filed.

Net loss

The Corporation recorded a net loss of $95.9 million or $0.65 per basic and diluted Common Share in 2011 as compared to a net loss of $100.7 million or $0.72 per basic and diluted Common Share in 2010. The reduction in the net loss was due to lower D&D charges, offset by reduced funds flows. The prior year loss also included $40.5 million in interest on Trust Units, as distributions to Unitholders are expensed through earnings under IFRS.

LIQUIDITY, CAPITALIZATION, FUTURE OPERATIONS AND FINANCIAL RESOURCES

Capitalization and financial resources ($ thousands except per Common Shares and percent amounts)	**2011**	Year ended December 31 2010	2009
Long-term bank debt	**130,062**	182,612	262,393
Senior Notes, measured at principal amount	**150,000**		-
Convertible debentures, measured at principal amount	**234,897**	234,897	230,168
Adjusted working capital deficiency (2)	**7,627**	31,934	8,450
Net debt	**522,586**	449,443	501,011
Common Shares outstanding at end of period (thousands)	**146,966**	148,284	126,224
Market price at end of year	**1.17**	3.93	5.22
Market value of Common Shares	**171,950**	582,756	658,889
Total capitalization (1)	**694,536**	1,032,199	1,159,900
Net debt as a percentage of total capitalization (%)	**75.2**	43.5	43.2
Funds flow (1)	**76,986**	237,470	231,347
Net debt to funds flow ratio (times) (1)	**6.8**	1.9	2.2

(1) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in this MD&A.

(2) Adjusted working capital deficiency (surplus) excludes short-term derivative assets and liabilities related to the Corporation's hedging activities, the current portion of convertible debentures, assets and liabilities held for sale and share-based payment liabilities. Working capital deficiency does not include approximately $9.0 million in gas over bitumen royalty adjustments not yet received as of December 31, 2011.

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 was reduced to $171 million from $190 million as a result of asset sales in the first quarter of 2012, with the next borrowing base review scheduled for April 2012. At current interest rates and applicable margins, the effective interest rate on the Corporation's bank debt is approximately 5.5 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 in respect of amounts borrowed under the facility. Bank debt drawn on Perpetual's credit facility decreased $52.6 million or 29 percent from December 31, 2010 due to the issuance of Senior Notes in 2011, partially offset by capital expenditures and dividends in excess of funds flows and net dispositions for the year.

Perpetual has an adjusted working capital deficiency of $7.6 million at December 31, 2011, as compared to a deficiency of $31.9 million at December 31, 2010. The decrease in the working capital deficiency is primarily related to lower WGSI capital spending in the fourth quarter of 2011 and the absence of dividends payable at December 31, 2011. The Corporation's working capital deficiency will be funded from future sales revenues and by additional borrowings from Perpetual's credit facility, as required.

Future operations

The Corporation has $75 million of 6.50% convertible unsecured subordinated debentures ("6.50% Debentures") maturing on June 30, 2012. While Perpetual may settle all or a portion of the outstanding 6.50% Debentures through the issuance of Common Shares by giving notice of such intent to Debenture holders not more than 30 and not less than 15 days prior to the maturity date, it is the intention of the Corporation to settle the 6.50% Debentures in cash.

To date in 2012, Perpetual has disposed of non-core oil and gas assets for total proceeds of approximately $61 million. In addition, as described in note 23 to the annual consolidated financial statements, the Corporation has identified the WGSI Facility as an asset held for sale subsequent to the balance sheet date. Perpetual anticipates that cash flows including cash flow from operating activities, proceeds from closed and future asset dispositions and available credit facilities will provide the required funds to discharge the Corporation's existing obligations, carry out exploration and development programs and fund ongoing operations for the foreseeable future, including the cash settlement of the 6.50% Debentures on the maturity date. Perpetual expects a downward adjustment to the borrowing base under the Credit Facility pursuant to the semi-annual redetermination of the borrowing base in April 2012, which relates principally to lower natural gas prices and the effects of asset dispositions. If available liquidity is not sufficient to meet the Corporation's operating and debt servicing obligations as they come due, management's plans include reducing expenditures as necessary or pursuing alternative financing arrangements for the foreseeable future.

Net debt to funds flow increased to 6.8 times for the year ended December 31, 2011 from 1.9 times for the year ended December 31, 2010 due to lower funds flows resulting from a reduction in gains on derivatives and higher overall debt levels. A reconciliation of the change in net debt from December 31, 2010 to December 31, 2011 is as follows.

Reconciliation of net debt ($ millions)	
Net debt, December 31, 2010	449.4
Capital expenditures (exploration and development, land acquisitions, gas storage and other)	151.0
Dispositions, net of acquisitions	(33.9)
Funds flow (1)	(77.0)
Dividends	28.9
Expenditures on asset retirement obligations	2.5
Repurchase of common shares	4.6
Issue costs on Senior Notes	3.8
Unrealized loss on marketable securities	2.6
Proceeds from gas storage arrangement, net of issue costs	(9.9)
Gas over bitumen royalty adjustments not yet received	0.6
Net debt, December 31, 2011	**522.6**

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

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 has 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 million (less $0.1 million in issue costs) in 2011. In exchange for the funds received, the Corporation has agreed to deliver 8 Bcf of natural gas to the counterparty during the first quarter of 2013. In 2011, Perpetual extended the delivery term to the first quarter of 2016 and subsequent to year-end has extended the term to 2018. The gas storage liability on the balance sheet combined with the related derivative asset represent 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. In the current year the Corporation recorded an unrealized gain of $4.1 million (2010–$3.7 million) on the statement of earnings (loss) related to the change in the forward price curves for natural gas.

Perpetual's future contractual obligations are summarized in the following table:

			Payments due by period		
Contractual obligations ($ millions)	Total	2012	2013-2014	2015-2016	Thereafter
Long-term bank debt (1)	130,062	-	130,062	-	-
Convertible debentures, principal	234,897	74,925	-	159,972	-
Senior notes, principal	150,000	-	-	-	150,000
Operating leases (3)	12,615	2,275	3,974	3,918	2,449
Pipeline commitments (2)	16,081	8,451	6,995	527	108
Total contractual obligations	543,655	85,651	141,031	164,417	152,557

(1) The revolving feature of Perpetual's credit facility expires on May 29, 2012 if not extended. Upon expiry of the revolving feature of the facility, should it not be extended, amounts outstanding as of the expiry date will have a term to maturity date of one additional year.

(2) The Corporation has long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada.

(3) Perpetual has office leases on its current office space ending on March 31, 2018. Office lease commitments are shown net of related sublease recoveries.

Convertible debentures

As at December 31, 2011, the Corporation 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. Additional information on convertible debentures is as follows.

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 (“TSX”)	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)	72.5	80.0	45.7

Fair values of debentures are calculated by multiplying the number of debentures outstanding at December 31, 2011 by the quoted market price per debenture at that date. None of the debentures were converted into common shares during the year ended December 31, 2011.

All series of debentures are redeemable by the Corporation at a premium to face value, pay interest semi-annually and are subordinated to substantially all other liabilities of Perpetual including the credit facility. The 7.0% Debentures are also subordinated to all other series of convertible debentures.

Senior notes

On March 15, 2011 the Corporation issued $150 million of seven-year Senior Notes for net proceeds of $146.2 million after issue costs. The Senior Notes bear interest at 8.75%, are unsecured and mature on March 15, 2018. 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.

Shareholders’ equity

Perpetual’s total capitalization was $694.5 million at December 31, 2011. Net debt to total capitalization increased to 75.2 percent at December 31, 2011 as compared to 43.5 percent for the prior year as the trading price of the Corporation’s Common Shares dropped by 70 percent during the year. In 2011 Perpetual had an active Normal Course Issuer Bid outstanding and repurchased a total of 1.6 million Common Shares from May to October 2011 at an average price of $2.93 per Common Share.

Weighted average Common Shares outstanding for 2011 totaled 147.7 million (2010 – 140.6 million). On December 31, 2011 there were 147.0 million Common Shares outstanding.

Dividends

Dividends for the year ended December 31, 2011 totaled $28.9 million or $0.195 per Common Share, as compared to $78.6 million or $0.56 per common share for 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 relatively soft demand, suggest that a recovery in gas prices may be further delayed. As favorable natural gas economic 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.

Reinstatement 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.

2011 dividends by month ($ per Common Share)

Payment Date	Dividend
February 15, 2011	0.03
March 15, 2011	0.03
April 15, 2011	0.03
May 16, 2011	0.03
June 15, 2011	0.015
July 15, 2011	0.015
August 15, 2011	0.015
September 15, 2011	0.015
October 17, 2011	0.015
Total (1)	**0.195**

(1) Total is based upon cash dividends declared during 2011.

SUMMARY OF QUARTERLY RESULTS

($ thousands except where noted)	**Dec 31, 2011**	Sept 30, 2011	June 30, 2011	Three months ended Mar 31, 2011
Oil and natural gas revenues (1)	**61,412**	58,400	67,097	60,900
Production (MMcfe/d)	**142.9**	135.5	150.3	140.7
Funds flow (2)	**15,893**	19,318	17,852	23,923
Per common share - basic	**0.11**	0.13	0.12	0.16
Net earnings (loss)	**(38,691)**	(24,343)	(5,626)	(27,260)
Per common share - basic	**(0.26)**	(0.17)	(0.04)	(0.18)
- diluted	**(0.26)**	(0.17)	(0.04)	(0.18)
Realized commodity price ($/Mcfe) (3)	**4.66**	4.46	4.61	4.68
Average AECO Monthly Index price ($/Mcf)	**3.44**	3.72	3.74	3.77

($ thousands except where noted)	Dec 31, 2010	Sept 30, 2010	June 30, 2010	Three months ended Mar 31, 2010
Oil and natural gas revenues (1)	61,718	61,254	64,108	73,139
Production (MMcfe/d)	145.1	151.0	165.2	149.2
Funds flow (2)	70,509	46,078	36,162	84,419
Per common share - basic (4)	0.48	0.32	0.25	0.66
Net earnings (loss)	(28,193)	(16,260)	(76,878)	20,612
Per common share - basic (4)	(0.19)	(0.11)	(0.54)	0.16
- diluted	(0.19)	(0.11)	(0.54)	0.15
Realized commodity price ($/Mcfe) (3)	7.83	6.18	5.54	9.78
Average AECO Monthly Index price ($/Mcf)	4.13	3.72	3.86	5.36

(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 natural gas price includes realized gains and losses on financial hedging and physical forward sales contracts, and oil and natural gas liquids revenues measured on a per Mcfe basis.
(4) Earnings (loss) is measured per Trust Unit outstanding for the first two quarters of 2010.

Oil and natural gas revenues are primarily a function of production levels and commodity prices before hedging. Revenues were highest in the first quarter of 2010 when AECO prices were highest, averaging $5.36 per Mcf. Perpetual uses derivatives as part of its risk management strategy to mitigate the effect of volatility in AECO prices on funds flows, and in recent quarters has shifted its asset development strategy to focus on oil and liquids-rich natural gas. Therefore funds flows will trend with Perpetual's production mix, realized commodity price and changes in production levels. Funds flows were highest in the first and fourth quarters of 2010 as a result of realized commodity prices of $9.78 and $7.83 per Mcfe, respectively. Funds flows are lowest in the fourth quarter of 2011 due to lower AECO prices and a reduction in realized derivative gains relative to previous quarters, leading to a realized commodity price of $4.66 per Mcfe.

Net earnings (loss) 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 balance sheet 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. Distributions paid in the first two quarters of 2010 were expensed through earnings, whereas dividends paid after the conversion to a corporation were direct reductions in equity. Net losses in the 2011 quarters are primarily due to low gas prices and the absence of significant realized gains on derivatives, which results in the Corporation's funds flow netback in those periods being less than non-cash charges such as D&D and accretion on decommissioning obligations.

2012 OUTLOOK AND SENSITIVITIES

Perpetual is nearing completion of a $34 million capital spending program for the first quarter of 2012. Capital expenditures were directed principally toward the advancement of Perpetual's two key commodity diversifying plays: horizontal development of the Wilrich in greater Edson, and exploration and development of heavy oil at Mannville.

- Two horizontal and one vertical (2.3 net) wells were drilled at Edson, in addition to facility construction to tie-in new production
- Two vertical and 12 horizontal (14.0 net) wells were drilled and tied-in at Mannville, and tie-in operations were completed for one well drilled in 2011.

As gas prices reached levels below $3.00 per Mcf in mid-January, investment in all natural gas projects including the Wilrich program was suspended and funds were redirected to the highly profitable Mannville heavy oil activities.

The Corporation's Board of Directors has approved a capital spending budget to remain within funds flow for 2012. Capital activity for the remainder of the year will be focused on Mannville heavy oil exploration and development.

Incorporating production additions from these capital expenditures, the following table shows Perpetual's estimate of funds flow for 2012 based on its current hedging portfolio and cost estimates under several different full year 2012 AECO gas price and WTI oil price assumptions, and incorporating all non-core property dispositions closed to date in 2012. Perpetual estimates 2012 annual production of 3,600 bbl/d of oil and NGL, 103 MMcf/d of natural gas, a $28 per bbl differential between WTI and WCS reference prices, $96 million in operating costs, $28 million in cash G&A expenses and a 5.5 percent interest rate on long-term bank debt.

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

		AECO Gas Price ($/GJ)				
Funds flow ($ millions)		**$1.75**	**$2.10**	**$2.50**	**$2.75**	**$3.00**
Edmonton oil price ($/bbl)	**$80.00**	30	32	34	35	36
	$90.00	33	35	37	38	39
	$100.00	37	39	40	42	43
	$110.00	37	39	40	42	43
	$120.00	37	39	40	42	43

Below is a table that shows sensitivities of Perpetual's 2012 estimated funds flow to operational changes and changes in the business environment:

		Impact on funds flow per Common Share	
Funds flow sensitivity analysis ($ per Common Share)	Change	Annual	Monthly
Business environment			
Natural gas price at AECO	$0.25 per Mcf	0.058	0.005
Oil price at WTI	$5.00 per bbl	0.041	0.003
Interest rate on bank debt	1%	0.007	0.001
Operational			
Natural gas production	5 MMcf/d	0.012	0.001
Oil and NGL production	100 bbl/d	0.029	0.002
Operating costs	$0.10 per Mcfe	0.0266	0.002
Cash general and administrative expenses	$0.10 per Mcfe	0.0266	0.002

CORPORATE GOVERNANCE

The Corporation is committed to maintaining high standards of corporate governance. Each regulatory body, including the Toronto Stock Exchange, the Canadian provincial securities commissions and the Securities and Exchange Commission ("SEC"), whose responsibilities include implementing rules under the United States Sarbanes-Oxley Act of 2002, has a different set of rules pertaining to corporate governance. The Corporation fully conforms to the rules of the governing bodies under which it operates.

CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As at December 31, 2011, an evaluation of the effectiveness of Perpetual's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities and by the SEC was carried out under the supervision and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on this evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that, as at December 31, 2011, the design and operation of Perpetual's disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Corporation in reports filed with, or submitted to, securities regulatory authorities is accumulated and communicated to management, including the President and Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure and were effective to provide reasonable assurance that such information is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.

Management's Annual Report on Internal Control over Financial Reporting

Internal control over financial reporting is a process designed by or under the supervision of senior management and effected by the Board of Directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with GAAP.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can only provide reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on this evaluation, management concluded that internal control over financial reporting was effective as at December 31, 2011, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

In 2011, there was no change in Perpetual's internal control over financial reporting that materially affected or is reasonably likely to materially affect Perpetual's internal control over financial reporting.

CEO and CFO Certifications

Perpetual's President and Chief Executive Officer and Chief Financial Officer have filed with the Canadian securities regulators the SEC certifications regarding the quality of Perpetual's public disclosures relating to its fiscal 2011 reports filed with the Canadian securities regulators and the SEC.

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 (loss) per common share or other measures of financial performance calculated in accordance with GAAP.

Revenue, including realized gains (losses) on derivatives

Revenue, including realized gains (losses) on derivatives, includes call option premiums received and is used by management to calculate the Corporation's net realized commodity prices taking into account monthly settlements on financial forward sales, collars and foreign exchange contracts. These contracts are put in place to protect Perpetual's funds flows from potential volatility in commodity prices, and as such any related realized gains or losses are considered part of the Corporation's realized price. Revenue, including realized gains (losses) on derivatives does 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-term derivative assets and liabilities related to the Corporation's hedging activities, the current portion of convertible debentures, restricted cash and liabilities related to Perpetual's stock option plan. Net debt includes Senior Notes and 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 GAAP and therefore these terms may not be comparable with the calculation of similar measures for other entities.

Total capitalization

Total capitalization is equal to net debt 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.

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 2 to the annual consolidated financial statements for the year ended December 31, 2011, and note 23 to annual consolidated 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 Previous 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 Previous 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 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, 2015. 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 net of decommissioning obligation 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.

NOTES PERTAINING TO THE REPORTING OF BITUMEN CONTINGENT RESOURCE

The following are excerpts from the definitions of resources and reserves, contained in Section 5 of the COGE Handbook, which is referenced by the Canadian Securities Administrators in National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities".

Definitions

Contingent Resources are 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. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. [Criteria for determining commerciality are further detailed in the COGE Handbook Section 5.3.4].

Discovered Petroleum Initially-In-Place (DPIIP) (equivalent to discovered resources) is 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.

Economic Contingent Resources are those contingent resources which are currently economically recoverable.

Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects.

Undiscovered Petroleum Initially-In-Place (UDPIIP) (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources"; the remainder as unrecoverable.

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

Uncertainty Categories for Resource Estimates

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.

Levels of Certainty for Reported Reserves

With respect to contingent resources, not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development." For contingent resources the chance of commerciality is equal to the chance of development.

Risk Factors

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. Any reference in this press release to DPIIP, UDPIIP, contingent resources and prospective resources are not, and should not be confused with oil and gas reserves.

RISK FACTORS

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 both the conventional oil and gas royalty trust sector and the conventional oil and gas producers sector. The Corporation's financial position, results of operations, and cash available for distribution to Shareholders are directly impacted by these factors.

Changes in tax legislation

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

Shut in natural gas reserves as a result of gas over bitumen issues

Recent decisions by the AEUB have brought into question our 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 AEUB has ordered shut-in of some of our production and reserves in this area.

The AEUB has also indicated that it believes there is a need to assess whether additional gas production should be curtailed in situations similar to those considered at hearings to-date and whether there is a need for a broad bitumen conservation strategy in all areas where natural gas production may interfere with eventual bitumen recovery. It is possible that such a strategy, when drafted and implemented by the ERCB (formerly AEUB), will affect future natural gas production from reservoirs owned by the Corporation and located within the gas over bitumen areas of concern as gas production from a portion or all of these zones may be identified in the future as posing a potential concern with respect to communication with potentially recoverable bitumen resources.

While we have no significant additional production recommended for shut-in by any party or the ERCB at this time and royalty adjustments are being received for most production currently shut-in, we cannot ensure that additional production will not be shut-in in the future or that we will be able to negotiate adequate compensation for having to shut-in any such production. This could have a material adverse effect on our funds flows and earnings.

Solution gas ownership

A portion of Perpetual's natural gas production is from properties where third parties hold bitumen rights. Certain of these third parties have suggested that "solution gas" exists within the bitumen and that therefore this solution gas is the property of the bitumen rights holder. If this is proven to be correct, and if it is demonstrated that this solution gas has been or may continue to be produced in association with the recovery of Perpetual's conventional natural gas rights, these facts may give rise to a third party claim for compensation. A successful claim in this regard may have a material adverse effect on the Corporation's business, financial condition and operations.

Exploration, development and production risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Substantial capital expenditures are required for exploration, development and production of oil and natural gas reserves in the future. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Prices, markets and marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

The Corporation manages commodity price uncertainty through financial hedges and physical forward sale arrangements. There is a credit risk associated with counterparties with which the Corporation may contract.

Failure to realize anticipated benefits of acquisitions and dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Project cost overruns could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation also competes with other companies for all of its business inputs including exploitation and development prospects, access to commodity markets, property and corporate acquisitions, and available capital. The Corporation endeavours to be competitive by maintaining a strong financial condition through attracting and retaining technically competent and accountable staff, by refining and enhancing business processes on an ongoing basis and by utilizing current technologies to enhance exploitation, development and operational activities. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations which it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require additional expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Variations in foreign exchange rates and interest rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the Common Shares.

Additional funding requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its bylaws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Availability of drilling equipment and access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Title to assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reserve estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

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

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date, and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geopolitical risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil and natural gas. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have an impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will not have insurance to protect against the risk from terrorism.

Management of growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of licenses and leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Cyclical and seasonal impact on industry

The Corporation's operational results and financial condition will be dependent on the prices received for natural gas production. Natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors including weather and general economic conditions, as well as conditions in other oil and natural gas producing regions. Any decline in natural gas prices could have an adverse effect on the Corporation's financial condition.

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity which could impact the production and future revenues of the Corporation. In addition high demand for equipment in winter months for areas limited to winter access could result in increased costs and the inability to execute the Corporation's desired exploration and development programs.

Third party credit risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, commodity price and currency hedge contract counterparties, and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the Alberta Business Corporations Act.

Reliance on key personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The contributions of the existing management team to the immediate and near-term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Administrator.

Operations in other jurisdictions and other business activities

Our operations and the expertise of our management are currently focused on conventional shallow and unconventional tight gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. In addition, the Articles of Incorporation does not limit the activities of the Corporation to oil and gas production and development, and the Corporation could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present new additional risks or alternatively, increase the exposure to one or more of the present risk factors, which may result in future operational and financial conditions of the Corporation being adversely affected. In either case, our future operational and financial conditions could be materially adversely affected.

Lender limitations on dividends on common shares

Under the terms of the credit facility with our lenders, if the lenders determine that our borrowing base under the facility has been exceeded by the amount loaned and assuming there is not a demand for repayment we will be precluded from paying dividends until our borrowing base no longer is in a shortfall position. Our lenders may also restrict our ability to pay dividends when we are in breach or default of agreements with the lenders.

The lenders will be provided with security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default such as bankruptcy, the lender may foreclose on or sell the working interests.

Dilution

To maintain or expand our natural gas reserves we will need to finance capital expenditures and property acquisitions. Consequently, you may suffer dilution as a result of any future offering of common shares or securities convertible into common shares.

GAAP

GAAP requires that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in our consolidated financial statements. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of the Corporation's common shares. The carrying value of property, plant and equipment, the carrying value of goodwill and the value of hedging instruments are some of the items which are subject to valuation and potential non-cash write-downs.

Permitted investments

We may invest in certain permitted investments of which the market value may fluctuate. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Other permitted investments in energy-related entities will be subject to the general risks of investing in equity securities. These include the risks that the financial condition of issuers may become impaired or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors including: governmental, environmental and regulatory policies; inflation and interest rates; economic cycles; and global, regional and national events. The value of the Common Shares could be affected by adverse changes in the market values of permitted investments.

Changes in dividends

The board of directors of the Corporation assess the dividend on a monthly basis based on cash flow projections which incorporate Perpetual's base production forecasts, current hedges and physical forward natural gas sales, the forward market for natural gas prices, and the Corporation's capital spending program and projected production additions. Future dividends are subject to change as dictated by changes in commodity price markets, operations and future business development opportunities and may vary materially from previous dividends.

Operational matters

The Corporation's operations may be delayed or unsuccessful for many reasons including cost overruns, lower natural gas prices, equipment shortages, mechanical and technical difficulties and labour problems. The Corporation's operations will also often require the use of new and advanced technologies which can be expensive to develop, purchase and implement and may not function as expected. Perpetual may experience substantial cost overruns caused by changes in the scope and magnitude of our operations, employee strikes and unforeseen technical problems including natural hazards which may result in blowouts, environmental damage or other unexpected or dangerous conditions giving rise to liability to third parties. In particular, drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. Drilling for natural gas could result in unprofitable efforts, not only from dry wells but from wells that are productive but do not produce enough net revenue to return a profit after drilling, operating and other costs. The costs of drilling, completing and operating wells are often uncertain. In addition, our operations depend on the availability of drilling and related equipment in the particular areas where exploration and development activities will be conducted. Demand for the equipment or access restrictions may affect the availability of that equipment and, consequently, delay operations.

Continuing production from a property, and to some extent marketing of production therefrom, is largely dependent upon economic variables and the ability of the operator of the property. Operating costs on most properties have increased over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Corporation to certain properties. A reduction in dividends on Common Shares could result in such circumstances.

Expansion of operations

The operations and expertise of management of the Corporation are currently focused on natural gas production and development in the Western Canadian Sedimentary Basin. In the future, the Corporation may acquire oil and gas properties outside this geographic area. In addition, the Articles of Incorporation does not limit the activities of the Corporation to oil and gas production and development, and the Corporation could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present new additional risks or alternatively, increase the exposure to one or more of the present risk factors, which may result in future operational and financial conditions of the Corporation being adversely affected.

Acquisitions

The price paid for asset acquisitions is based on the Corporation's internal assessment of the reserves and future production potential adjusted for risk. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas, and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators of the working interests, management and the Corporation. In particular, changes in prices of and markets for petroleum and natural gas from those anticipated at the time of making such assessments will affect the amount of future dividends and as such the value of the Common Shares. In addition, all such estimates involve a measure of geological and engineering uncertainty which could result in lower production and reserves than attributed to the working interests. Actual reserves could vary materially from these estimates. Consequently, the reserves acquired may be less than expected, which could adversely impact funds flows and dividends to Shareholders.

Net asset value

The net asset value of the assets of the Corporation will vary from time to time dependent upon a number of factors beyond the control of management, including oil and natural gas prices. The trading prices of the Common Shares from time to time are also determined by a number of factors that are beyond the control of management and such trading prices may vary from the net asset value of the Corporation's assets.

Financial instruments

The nature of Perpetual's operations results in exposure to fluctuations in commodity prices. The Corporation will monitor and, when appropriate, utilize derivative financial instruments and physical delivery contracts to mitigate its exposure to these risks. Perpetual may be exposed to credit-related losses in the event of non-performance by counter-parties to the financial instruments. From time to time the Corporation may enter into risk management activities in an effort to mitigate the potential impact of declines in natural gas prices. These activities may consist of, but are not limited to:

- buying a price floor under which the Corporation will receive a minimum price for natural gas production;
- buying a collar under which the Corporation will receive a price within a specified price range for natural gas production;
- selling call options to third parties, giving them the right to purchase natural gas from the Corporation at a specified price in future periods in exchange for an upfront cash payment to Perpetual;
- entering into fixed price contract for natural gas production; and
- entering into contracts to fix the basis differential between natural gas markets.

If product prices increase above the levels specified in Perpetual's various hedging agreements, the Corporation would be precluded from receiving the full benefit of commodity price increases.

In addition, by entering into these hedging activities the Corporation may suffer financial loss if:

- Perpetual is unable to produce sufficient quantities of natural gas to fulfill its obligations;
- Perpetual is required to pay a margin call on a financial hedge contract; or
- Perpetual is required to pay royalties based on a market or reference price that is higher than its hedged fixed or ceiling price.

Renegotiation or termination of contracts

As at the date hereof, the Corporation does not anticipate that any aspect of its business will be materially affected in the current fiscal year by the renegotiation or termination of contracts or subcontracts.

Environmental considerations

Compliance with health, safety and environmental laws and regulations could materially increase the Corporation's costs. Perpetual will incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. These include costs to reduce certain types of air emissions and discharges and to remediate contamination at various facilities and third party sites where the Corporation's products or wastes will be handled or disposed.

Perpetual is subject to statutory strict liability in respect of losses or damages suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of the Corporation's licenses. As a result, anyone who suffers losses or damages as a result of pollution caused by Perpetual's operations can claim compensation without needing to demonstrate that the damage is due to any fault on the Corporation's part.

New laws and regulations, tougher requirements in licensing, increasingly strict enforcement of, or new interpretations of, existing laws and regulations and the discovery of previously unknown contamination may require future expenditures to:

- modify operations;
- install pollution control equipment;
- perform site clean-ups; or
- curtail or cease certain operations.

In addition, increasingly strict environmental requirements may affect product specifications and operational practices. Future expenditures to meet such specifications could have a material adverse effect on the Corporation's operations or financial condition. Any abandonment costs Perpetual incurs will reduce cash available for dividends to Shareholders and other uses.

The Corporation is proactive in its approach to environmental concerns. Procedures are in place to ensure that due care is taken in the day-to-day management of its properties. All government regulations and procedures are followed in adherence to the law. The Corporation believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to the Corporation.

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, oil and other risk management 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 costs and timing of future abandonment and reclamation, 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 Corporations's asset base; expected costs relating to the Corporation's gas storage project; anticipated future capacity of the Corporation's gas storage facility; the timing of receipt of escrowed funds; 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; funds flow; 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, and the effect thereof; 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.

The Corporation 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 the 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. 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 at www.sedar.com or from the Corporation's website at www.perpetualenergyinc.com.

MANAGEMENT'S REPORT

The consolidated financial statements of Perpetual Energy Inc. ("Perpetual" or "the Corporation") are the responsibility of Management and have been approved by the Board of Directors of Perpetual. These consolidated financial statements have been prepared by Management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and the Interpretations of the International Financial Reporting Interpretations Committee.

The consolidated financial statements are audited and have been prepared using accounting policies in accordance with IFRS. The preparation of Management's Discussion and Analysis is based on Perpetual's financial results which have been prepared in accordance with IFRS. It compares Perpetual's financial performance in 2011 to 2010 and should be read in conjunction with the consolidated financial statements and accompanying notes.

Management is responsible for establishing and maintaining adequate internal control over Perpetual's financial reporting. Management believes that the system of internal controls that have been designed and maintained at Perpetual provide reasonable assurance that financial records are reliable and form a proper basis for preparation of financial statements. The internal accounting control process includes Management's communication to employees of policies which govern ethical business conduct.

Under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, Management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment according to these criteria, Management concluded that internal control over financial reporting is effective as of December 31, 2011 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with IFRS.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Board of Directors has appointed an Audit Committee consisting of unrelated, non-management directors which meets at least four times during the year with Management and independently with the external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the charter of the Audit Committee as set out in the Annual Information Form. The Audit Committee reviews the consolidated financial statements and Management's Discussion and Analysis before the consolidated financial statements are submitted to the Board of Directors for approval. The external auditors have free access to the Audit Committee without obtaining prior Management approval.

With respect to the external auditors, KPMG LLP, the Audit Committee approves the terms of engagement and reviews the annual audit plan, the Auditors' Report and results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The independent external auditors, KPMG LLP, have been appointed by the Board of Directors on behalf of the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, Perpetual's financial position, results of operations and cash flows in accordance with IFRS. The report of KPMG LLP outlines the scope of their examination and their opinion on the consolidated financial statements.

SUSAN L. RIDDELL ROSE
President &
Chief Executive Officer

CAMERON R. SEBASTIAN
Vice President, Finance &
Chief Financial Officer

March 12, 2012

INDEPENDENT AUDITORS' REPORT

To the Shareholders and Board of Directors of Perpetual Energy Inc.

We have audited the accompanying consolidated financial statements of Perpetual Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of loss and comprehensive loss, changes in equity and cash flows for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Perpetual Energy Inc. as at December 31, 2011, December 31, 2010 and January 1, 2010, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, Canada

March 12, 2012

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	**December 31, 2011**	December 31, 2010	January 1, 2010
(Cdn$ thousands)		(note 24)	(note 24)
Assets			
Current assets			
Accounts receivable	**$ 35,604**	$ 35,459	$ 34,079
Prepaid expenses and deposits	**3,891**	5,028	12,910
Marketable securities	**3,282**	6,007	163
Derivatives (note 17)	**12,604**	4,271	46,152
Assets held for sale (note 4)	**20,325**	–	–
	75,706	50,765	93,304
Derivatives (note 17)	**7,692**	3,562	21,167
Property, plant and equipment (note 5)	**827,928**	859,465	872,156
Exploration and evaluation (note 6)	**106,763**	107,474	111,604
Goodwill (note 7)	**–**	6,000	6,000
	942,383	976,501	1,010,927
Total assets	**$ 1,018,089**	$ 1,027,266	$ 1,104,231
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**$ 50,404**	$ 73,979	$ 41,722
Dividends payable	**–**	4,449	6,311
Share based payment liability (note 14)	**664**	2,130	8,571
Bank debt (note 8)	**–**	–	7,569
Convertible debentures (note 10)	**74,250**	–	55,271
Derivatives (note 17)	**6,841**	–	–
Liabilities associated with assets held for sale (note 4)	**4,843**	–	–
	137,002	80,558	119,444
Derivatives (note 17)	**10,865**	–	–
Long-term bank debt (note 8)	**130,062**	182,612	262,393
Senior notes (note 9)	**146,634**	–	–
Convertible debentures (note 10)	**149,020**	219,689	164,926
Derivative debenture liability (note 10)	**–**	–	8,398
Gas storage obligation (note 11)	**41,630**	31,721	–
Gas over bitumen royalty obligation (note 12)	**74,705**	70,497	77,167
Decommissioning obligations (note 15)	**242,860**	236,163	253,344
Deferred tax liability (note 20)	**3,753**	2,122	–
Unitholders' liability (note 13)	**–**	–	1,156,245
	799,529	742,804	1,922,473
Total liabilities	**936,531**	823,362	2,041,917
Equity			
Share capital (note 13)	**1,254,273**	1,257,462	–
Equity component of convertible debentures	**13,988**	13,988	–
Contributed surplus (note 14)	**15,496**	9,868	–
Deficit	**(1,202,199)**	(1,077,414)	(939,165)
Total equity attributable to shareholders	**81,558**	203,904	(939,165)
Non-controlling interests	**–**	–	1,479
Total equity	**81,558**	203,904	(937,686)
Total liabilities and equity	**$ 1,018,089**	$ 1,027,266	$ 1,104,231

See accompanying notes. The notes are an integral part of the Corporation's annual consolidated financial statements.

Robert A. Maitland
Director

Geoffrey C. Merritt
Director

CONSOLIDATED STATEMENTS OF LOSS AND COMPREHENSIVE LOSS

	Year ended December 31	
	2011	2010
(Cdn$ thousands, except per share amounts)		(note 24)
Revenue		
Oil and natural gas	**$ 247,809**	$ 260,217
Royalties	**(20,624)**	(22,131)
	227,185	238,086
Change in fair value of derivatives (note 17)	**(4,019)**	93,661
Gas over bitumen (note 12)	**6,739**	15,616
	229,905	347,363
Expenses		
Production and operating	**89,322**	91,161
Transportation	**10,350**	11,888
Exploration and evaluation (note 6)	**15,997**	18,293
General and administrative	**35,712**	39,663
Gain on dispositions of property, plant and equipment (note 5)	**(12,033)**	(41,830)
Impairment losses (note 5)	**25,607**	24,261
Depletion and depreciation (note 5)	**116,050**	225,022
	281,005	368,458
Loss from operating activities	**(51,100)**	(21,095)
Financial items		
Unrealized loss on derivative debenture liability (note 10)	**–**	130
Unrealized gain on gas storage obligation derivative (note 11)	**(4,117)**	(3,729)
Unrealized loss on marketable securities	**2,625**	1,257
Interest on Trust Units (note 13)	**–**	40,549
Interest on convertible debentures	**19,879**	19,492
Interest on senior notes	**10,866**	–
Interest on debt and gas storage obligation	**6,645**	12,155
Accretion on decommissioning obligations (note 15)	**7,291**	7,648
	43,189	77,502
Loss before income tax	**(94,289)**	(98,597)
Deferred income taxes (note 20)	**1,631**	2,122
Net loss and comprehensive loss	**(95,920)**	(100,719)
Net loss and comprehensive loss attributable to:		
Shareholders of the Corporation	**(95,920)**	(100,169)
Non-controlling interests	**–**	(550)
	$ (95,920)	$ (100,719)
Loss per share (note 13)		
Basic and diluted	**$ (0.65)**	$ (0.72)

See accompanying notes. The notes are an integral part of the Corporation's annual consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(Cdn$ thousands)	Share Capital	Equity Component of Convertible Debentures	Contributed Surplus	Deficit	Total Equity
Balance at January 1, 2011 (note 24)	$ 1,257,462	$ 13,988	$ 9,868	$ (1,077,414)	$ 203,904
Net loss	–	–	–	(95,920)	(95,920)
Dividends to shareholders (note 13)	–	–	–	(28,865)	(28,865)
Common shares issued – Restricted Rights Plan	1,043	–	(1,043)	–	–
Common shares issued – Share Option Plan	494	–	(413)	–	81
Common shares repurchased	(4,718)	–	–	–	(4,718)
Issue fees incurred	(8)	–	–	–	(8)
Share based payment expense	–	–	5,618	–	5,618
Share based payment liability	–	–	1,466	–	1,466
Balance at December 31, 2011	**$ 1,254,273**	**$ 13,988**	**$ 15,496**	**$ (1,202,199)**	**$ 81,558**

(Cdn$ thousands)	Share Capital	Equity Component of Convertible Debentures	Contributed Surplus	Deficit	Non-controlling Interests	Total Equity
Balance at January 1, 2010 (note 24)	$ –	$ –	$ –	$ (939,165)	$ 1,479	$ (937,686)
Net loss	–	–	–	(100,169)	(550)	(100,719)
Severo common share issue	–	–	–	–	550	550
Dividends to shareholders (note 13)	–	–	–	(38,080)	–	(38,080)
Share based payment expense	–	–	2,606	–	–	2,606
Share based payment liability	–	–	(1,778)	–	–	(1,778)
Common shares issued – Restricted Rights Plan	675	–	(240)	–	–	435
Common shares issued – Share Option Plan	15	–	(373)	–	–	(358)
Common shares issued – Premium Dividend Reinvestment Plan	19,535	–	–	–	–	19,535
Issue fees incurred	(258)	–	–	–	–	(258)
Acquisition of non-controlling interests	1,479	–	–	–	(1,479)	–
Transferred upon conversion (note 24)	1,236,016	13,988	9,653	–	–	1,259,657
Balance at December 31, 2010 (note 24)	$ 1,257,462	$ 13,988	$ 9,868	$ (1,077,414)	$ –	$ 203,904

See accompanying notes. The notes are an integral part of the Corporation's annual consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31 2011	2010
(Cdn$ thousands)		(note 24)
Cash flows from operating activities		
Net loss	**$ (95,920)**	$ (100,719)
Adjustments to add (deduct) non-cash items:		
Change in fair value of derivatives	**9,360**	63,215
Exploration and evaluation	**8,201**	9,824
Share based payment expense	**5,618**	5,283
Gain on disposition of property, plant and equipment	**(12,033)**	(41,830)
Impairment losses	**25,607**	24,261
Depletion and depreciation	**116,050**	225,022
Unrealized loss on derivative debenture liability	**–**	130
Unrealized gain on gas storage obligation derivative	**(4,117)**	(3,729)
Unrealized loss on marketable securities	**2,625**	1,257
Interest expense on convertible debentures	**3,581**	3,720
Interest expense on senior notes	**403**	–
Accretion on decommissioning obligations	**7,291**	7,648
Deferred income tax expense	**1,631**	2,122
Gas over bitumen royalty obligation adjustments	**4,772**	10,454
Gas over bitumen royalty obligation adjustments not yet received	**(564)**	(3,357)
Gas over bitumen royalty obligation adjustments on dispositions	**–**	(13,767)
Expenditures on decommissioning obligations	**(2,514)**	(4,880)
Change in non-cash working capital (note 16)	**(9,563)**	15,228
Net cash from operating activities	**60,428**	199,882
Cash flows from financing activities		
Change in bank debt	**(52,550)**	(87,351)
Senior notes issued net of issue fees	**146,231**	–
Gas storage arrangement receipt net of issue fees	**9,909**	31,150
Dividends to shareholders	**(28,865)**	(18,544)
Proceeds from Premium Dividend Reinvestment Plan	**–**	23,784
Repayment of convertible debentures	**–**	(55,271)
Convertible debenture issue net of issue fees	**–**	57,073
Common shares issued net of issue fees	**73**	54,564
Commons share repurchased	**(4,718)**	–
Severo common share issue	**–**	549
Change in non-cash working capital (note 16)	**(6,904)**	2,107
Net cash from financing activities	**63,176**	8,061
Cash flows from investing activities		
Acquisitions	**(8,295)**	(142,917)
Capital expenditures	**(146,504)**	(168,759)
Proceeds on dispositions	**41,660**	84,169
Proceeds on sale of marketable securities	**100**	–
Change in non-cash working capital (note 16)	**(10,565)**	19,564
Net cash used in investing activities	**(123,604)**	(207,943)
Change in cash	**–**	–
Cash, beginning of year	**–**	–
Cash, end of year	**$ –**	$ –
Interest paid	**$ 30,291**	$ 25,278
Taxes paid	**$ –**	$ –

See accompanying notes. The notes are an integral part of the Corporation's annual consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(All tabular amounts are in Cdn$ thousands, except where otherwise noted)

1. REPORTING ENTITY AND FUTURE OPERATIONS

a) Reporting entity

Perpetual Energy Inc. ("Perpetual" or the "Corporation") is a corporation domiciled in Canada. The address of the Corporation's registered office is 3200, 605 – 5 Avenue S.W., Calgary, Alberta. The consolidated financial statements of the Corporation as at December 31, 2011 comprise the Corporation and its subsidiaries (note 21).

Perpetual is principally engaged in the acquisition, exploration and development of oil and gas properties in Alberta. Historically the Corporation has concentrated on conventional shallow gas properties as a basis for stable production. The Corporation also takes advantage of other energy opportunities which present themselves, including tight gas, light oil and natural gas storage.

The Corporation formerly operated as Paramount Energy Trust ("PET" or the "Trust"), an unincorporated trust formed under the laws of the Province of Alberta pursuant to a trust indenture dated June 28, 2002. On June 30, 2010, the Trust completed a conversion (the "conversion") from an income trust to a corporation through a distribution of Trust Units for shares of Perpetual on a one-for-one basis pursuant to a plan of arrangement under the Business Corporations Act (Alberta) and related transactions. Perpetual's Board of Directors and management team are the former Board of Directors and management team of the Trust's administrator. Immediately subsequent to the conversion, Perpetual effected an internal reorganization whereby, among other things, the Trust was dissolved and the Corporation received all of the assets and assumed all of the liabilities of the Trust. As the conversion arose from a transfer of interests that were under control of the same Unitholders/Shareholders immediately before and after the conversion, the assets and liabilities acquired were recognized at the carrying amounts recognized previously in the Trust's consolidated financial statements. References to the Corporation in these consolidated financial statements for periods prior to June 30, 2010 are references to the Trust and for periods on or after June 30, 2010 are references to Perpetual. Additionally, references to shares, Shareholders and dividends are comparable to units, Unitholders and distributions previously under the Trust.

b) Future operations

The Corporation's $75 million 6.50% convertible unsecured subordinated debentures ("6.50% Convertible Debentures") mature on June 30, 2012. While the Corporation may settle all or a portion of the outstanding 6.50% Convertible Debentures through the issuance of Common Shares by giving notice of such intent to debenture holders not more than 30 and not less than 15 days prior to the maturity date, it is the intention of the Corporation to settle the 6.50% Convertible Debentures in cash.

To date in 2012, the Corporation has disposed of non-core oil and gas assets for total proceeds of approximately $60.9 million. In addition, as described in note 23, the Corporation has identified the Warwick gas storage facility as an asset held for sale subsequent to December 31, 2011. The Corporation anticipates that cash flows including cash flow from operating activities, proceeds from closed and future asset dispositions and available credit facilities will provide the required funds to discharge the Corporation's existing obligations, carry out exploration and development programs and fund ongoing operations for the foreseeable future, including the cash settlement of the 6.50% Convertible Debentures on the maturity date. The Corporation expects a downward adjustment to the borrowing base under the revolving credit facility ("Credit Facility") pursuant to the semi-annual redetermination of the borrowing base in April 2012, which relates principally to lower natural gas prices and the effects of asset dispositions. If available liquidity is not sufficient to meet the Corporation's operating and debt servicing obligations as they come due, management's plans include reducing expenditures as necessary or pursuing alternative financing arrangements for the foreseeable future.

2. BASIS OF PRESENTATION

a) Statement of compliance

These consolidated financial statements present the Corporation's first consolidated annual financial statements in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). These are Perpetual's first consolidated financial statements prepared in accordance with IFRSs and IFRS 1 First-time Adoption of International Financial Reporting Standards. Previously, the Corporation prepared its consolidated annual consolidated financial statements in accordance Canadian generally accepted accounting principles ("GAAP"). An explanation of how the transition from Canadian GAAP to IFRS has affected Perpetual's reported financial position, financial performance and cash flows is provided in note 24.

The consolidated financial statements of the Corporation were approved and authorized for issue by the Board of Directors on March 12, 2012.

b) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis except for financial assets or liabilities measured at fair value through profit or loss and liabilities for cash-settled share based payment arrangements measured at fair value.

c) Functional and presentation currency

These consolidated financial statements are presented in Canadian dollars, which is the functional currency of the Corporation and its subsidiaries.

d) Use of estimates and judgments

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenue and expenses.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. Actual results may differ from estimates.

Information about the significant estimates and judgments made by management in preparing these consolidated financial statements are outlined below.

The Corporation uses estimates of natural gas and liquids reserves in the calculation of depreciation and depletion and also for value in use and fair value less costs to sell ("FVLCS") calculations of non-financial assets. By their nature, the estimates of reserves, including estimates of price, costs, discount rates and the related future cash flows, are subject to measurement uncertainty.

The Corporation allocates its oil and natural gas properties to cash generating units ("CGUs") based on management's judgment of the CGU's ability to generate independent cash flows and for impairment testing.

The transfer of exploration and evaluation ("E&E") assets to property, plant and equipment is based on estimated reserves used in the determination of an asset's technical feasibility and commercial viability.

Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of asset retirement costs, site remediation and related cash flows.

Derivatives are measured at fair value which is subject to management uncertainty.

The determination of fair value of share based payments is based on estimates of future consideration using a binomial lattice option pricing model which requires assumptions such as volatility, dividend yield, risk free interest rate and expected term.

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.

The calculation of the gas storage obligation requires estimates and judgment to determine the estimated net present value of the future delivery obligation for cushion gas under the gas storage obligation.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these annual consolidated financial statements, and have been applied consistently by the Corporation and its subsidiaries.

a) Basis of consolidation

i) Subsidiaries

Subsidiaries are entities controlled by the Corporation. Control exists when the Corporation has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

ii) 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.

iii) Jointly controlled operations and jointly controlled assets

Many of the Corporation's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Corporation's proportionate share of these jointly controlled assets, liabilities, revenue and expenses.

iv) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the annual consolidated financial statements.

b) Financial instruments

Financial instruments are initially recognized at fair value on the statement of financial position. Subsequent measurement of financial instruments is based on their initial classification into one of the following categories: financial assets and liabilities measured at fair value through profit or loss, loans and receivables, held to maturity investments, available-for-sale financial assets, or other financial liabilities.

i) Non-derivative financial assets

Financial Instrument	Category	Subsequent Measurement
Accounts receivable	Loans and receivables	Amortized cost
Marketable securities	Fair value through profit or loss	Fair value

The Corporation's accounts receivable are initially recognized on the date they originate and are measured at amortized cost using the effective interest method, less any impairment losses.

Marketable securities are classified at fair value through profit or loss as the Corporation manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Corporation's risk management or investment strategy. Upon initial recognition, all transaction costs are recognized in net earnings or loss when incurred. At the period end date, marketable securities are measured at fair value derived from exchange traded values in active markets, any changes in the fair value are recognized in net earnings or loss.

ii) Derivative assets and liabilities

The Corporation has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices and currency rates. The Corporation has not designated its financial derivative contracts as effective accounting hedges, and thus not applied hedge accounting, even though the Corporation considers all commodity and currency contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and recorded as derivatives on the statement of financial position at fair value. Changes in the fair value of the commodity price and currency rate derivatives are recognized in net earnings or loss.

The Corporation has accounted for its forward physical delivery fixed-price sales contracts as derivative financial instruments, as the Corporation has settled such arrangements from time to time. Accordingly, such forward physical delivery fixed-price sales contracts are classified as fair value through profit or loss and recorded as derivatives on the statement of financial position at fair value.

Transaction costs on derivatives are recognized in net earnings or loss when incurred.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in net earnings or loss.

With respect to the gas storage obligation, the Corporation recognizes a derivative separate from the obligation relating to the change in the fair value of the natural gas to be delivered on maturity of the arrangement based on inputs including the forward price curves for natural gas. The corresponding change in the fair value of the embedded derivative is recognized in net earnings or loss.

iii) Non-derivative financial liabilities

Financial Instrument	Category	Subsequent Measurement
Accounts payable and accrued liabilities	Financial liabilities	Amortized cost
Dividends payable	Financial liabilities	Amortized cost
Long-term bank debt	Financial liabilities	Amortized cost
Senior notes	Financial liabilities	Amortized cost
Convertible debentures	Financial liabilities	Amortized cost
Gas storage obligation	Financial liabilities	Amortized cost
Unitholders’ liability	Financial liabilities	Amortized cost

Accounts payable and accrued liabilities, dividends payable, long-term bank debt and Senior Notes are recognized initially at fair value and are subsequently measured at amortized cost using the effective interest method.

The Corporation’s convertible debentures are classified as debt with a portion of the proceeds allocated to equity representing the conversion feature. As the debentures are converted, a portion of debt and conversion feature components are transferred to share capital. The debt component associated with the convertible debentures accretes over time to the amount owing on maturity and such increases in the debt component are reflected as non-cash interest expense in net earnings or loss. The convertible debentures are carried net of issue costs on the statement of financial position. The issue costs are amortized to net earnings or loss using the effective interest rate method.

The Corporation has a forward sales arrangement with a counterparty to fund the development of the Warwick gas storage facility, whereby the Corporation received cash in exchange for agreeing to deliver natural gas to the counterparty in the future. Upon receiving cash, a gas storage obligation is recorded. The obligation is accreted until its maturity using the effective interest method.

iv) Share capital and Unitholders’ liability

Prior to June 30, 2010, the Corporation was a Trust. The redeemable feature of the Trust Units along with the unavoidable requirement for distributions to be paid out according to the provisions of the trust indenture caused the Trust Units to be classified as a Unitholders’ liability until the Trust’s conversion. The Trust Units were recorded at amortized cost.

Due to the Trust Units being classified as a liability the conversion feature of the convertible debentures was recorded as a derivative debenture liability. The derivative debenture liability was measured at fair value at each period end date while the Corporation was a trust.

Upon conversion, the Unitholders’ liability was reclassified to equity at its June 30, 2010 carrying amount. Similarly to the Trust Units, the derivative debenture liability component of the convertible debentures was reclassified to equity upon the conversion at its June 30, 2010 carrying amount.

Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

c) Property, plant and equipment

i) Production and development costs

The technical feasibility and commercial viability of extracting oil and natural gas is considered to be determinable when commercial reserves are determined to exist. Upon determination of commercial reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to a separate category within tangible assets referred to as oil and natural gas properties.

Items of property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing.

The Corporation has grouped its development and production assets into CGUs of oil and natural gas properties in geographical areas in Alberta, including the Warwick gas storage facility and shut-in fields under the Government of Alberta's gas over bitumen royalty regime. There are no significant parts of an item of property, plant and equipment, including oil and natural gas properties, that have different useful lives from the life of the area or facility in general, that had to be accounted for as separate items.

Gains and losses on disposition of an item of property, plant and equipment, including oil and natural gas properties, are determined by comparing the proceeds from disposition with the carrying amount of property, plant and equipment and are recognized in net earnings or loss. The carrying amount of any replaced or disposed component is derecognized.

ii) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as property, plant and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in net earnings or loss as incurred. Such capitalized property, plant and equipment generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The costs of the day-to-day servicing of property, plant and equipment are recognized in net earnings or loss incurred.

iii) Depletion and depreciation

The net carrying amount of development or production assets is depleted using the unit of production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development and decommissioning costs necessary to bring those reserves into production. Future development and decommissioning costs are estimated taking into account the level of development required to produce the reserves. The future development cost estimates are reviewed by independent reserve engineers at least annually.

The Corporation revised its estimate of the depletion and depreciation rate of its oil and gas properties on January 1, 2011 to include probable reserves and associated future development and decommissioning costs. The effect of this change reduced depletion and depreciation expense by $119.8 million compared to depletion and depreciation expense as would have been calculated using proved reserves and associated future development and decommissioning costs for the year ended December 31, 2011. The amount of the effect on future periods has not been disclosed because estimating it is impracticable.

The Corporation's oil and natural gas properties are depleted on the unit of production method over expected field lives ranging from five to 15 years.

The Corporation's corporate assets are depreciated on a straight line basis at rates ranging from ten to 33 percent. Gas storage assets are depreciated using a five percent declining balance method.

Depreciation methods, useful lives and residual values are reviewed at each period end date.

d) Exploration and evaluation expenditures

Pre-license costs, geological and geophysical costs and lease rentals of undeveloped properties are recognized in net earnings or loss as incurred.

E&E costs, consisting of the costs of acquiring oil and natural gas licenses, are capitalized initially as E&E assets according to the nature of the assets acquired. Costs associated with drilling exploratory wells in an undeveloped area will be capitalized. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability. When technical feasibility and commercial viability is determined, the relevant expenditure is transferred to oil and gas properties after impairment is assessed and any resulting impairment loss if applicable is recognized to net earnings or loss. In addition, the Corporation tests for impairment if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The Corporation's E&E assets consist solely of undeveloped land and bitumen evaluation assets. Gains and losses on disposition of E&E assets are determined by comparing the proceeds from disposition with the carrying amount and are recognized in net earnings or loss.

e) Goodwill

Goodwill arises on the acquisition of businesses, subsidiaries, associates and joint ventures and represents the excess of the cost of the acquisition over the recognized amounts (generally fair value) of the identifiable assets, liabilities and contingent liabilities of the acquiree. Goodwill is measured at cost less accumulated impairment losses. 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.

f) Assets held for sale

Non-current assets, or disposal groups consisting of assets and liabilities ("disposal groups"), are classified as held for sale if their carrying amounts will be recovered principally through a sale transaction rather than through continuing use. Assets and liabilities qualifying as held for sale must be available for immediate sale in its present condition subject to normal terms and conditions and its sale must be highly probable.

Non-current assets, or disposal groups, are measured at the lower of the carrying amount and FVLCS, with impairments recognized in net earnings or loss. Non-current assets or disposal groups held for sale are presented in current assets and liabilities within the Statement of Financial Position. Assets held for sale are not subject to depletion and depreciation.

g) Impairment

i) Financial assets

Financial assets are assessed at each period end date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net earnings or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in net earnings or loss.

ii) Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than E&E assets, are reviewed at each period end date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. An impairment test is completed each year for goodwill and other intangible assets that have indefinite lives or that are not yet available for use. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as oil and natural gas properties, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together at a CGU level which is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is determined based on the higher of its FVLCS and its value in use.

FVLCS is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCS of oil and gas properties is generally determined as the net present value of estimated future cash flows expected to arise from the continued use of the CGU and its eventual disposition, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a new present value of the CGU.

In determining value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally determined by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

Goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to the CGUs that are expected to benefit from the synergies of the combination. E&E assets are allocated to related CGUs when they are assessed for impairment, both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to oil and natural gas properties in property, plant and equipment.

An impairment loss is recognized if the carrying amount of an asset or its CGU, including the related decommissioning obligation, exceeds its estimated recoverable amount. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis. Impairment losses are recognized in net earnings or loss.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior years are assessed at each period end date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

h) Share based payments

Options to purchase common shares issued under the Share Option Plan are treated as equity-settled share based payments and are measured at grant date fair value by means of a binomial lattice option pricing model which takes the exercise price of the option to purchase a share, the price of the share at the grant date, the expected life of the grant based on the vesting date and expiry date, estimates of volatility and interest rates over its expected life. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest. The grant date fair value of Share Options granted is recognized as share based payments, within general and administrative expenses, with a corresponding increase in contributed surplus over the vesting period. When Share Options are exercised for common shares, consideration paid by the option holder and associated contributed surplus is recorded to share capital.

The Dividend Bonus Arrangement is treated as a cash-settled share based payment plan, and as such the fair values of estimated dividend bonus obligations are adjusted at each period end date until settled. The fair value of the Dividend Bonus Arrangement for Share Options outstanding at June 30, 2010, is recorded as a share based payment liability and the increase or decrease in the fair value during the period, up to a maximum of the original grant date fair value, is charged or credited to contributed surplus. Any fair value calculated in excess of the original grant date fair value of the share options at June 30, 2010 and the fair value for the Dividend Bonus Arrangement related to the Share Options issued subsequent to June 30, 2010 is recorded to share based payments, within general and administrative expenses.

Restricted Rights issued under the Restricted Rights Plan and Performance Share Rights issued under the Performance Share Rights Plan are treated as equity-settled share based payments and are measured at grant date fair value and charged to net earnings or loss in the period they vest, within general and administrative expenses, with a corresponding increase to contributed surplus.

i) Gas over bitumen royalty obligation

Royalty adjustments received related to the Corporation's gas over bitumen properties are recorded as a liability as the Corporation cannot determine if, when or to what extent the royalty adjustment may be repayable through incremental royalties if and when gas production recommences. Therefore, these royalty adjustments will be included in net earnings or loss when such determination can be made. For certain wells which have been disposed to a third party, the Corporation continues to receive the gas over bitumen royalty adjustments although the ownership of the natural gas reserves and responsibility for paying royalties on future production has been transferred to the buyer and as a result the obligation is extinguished. Adjustments received for these wells are recorded as gas over bitumen revenue.

j) Decommissioning obligations

The Corporation's activities give rise to dismantling, decommissioning and site disturbance remediation activities. A provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's estimate of expenditures required to settle the present obligation at the statement of financial position date and using a risk free interest rate not adjusted for credit risk ("risk free rate"). Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation and changes in the risk free rate. The accretion of the provision due to the passage of time is recognized in net earnings or loss whereas changes in the provision arising from the changes in estimated cash flows or changes in the risk free rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

k) Revenue

Revenue and royalty expense from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline.

The Corporation recognizes revenue for storage services, including gas injection, storage and withdrawal in accordance with the terms of the storage contracts. The Corporation does not hold title to third party storage gas and does not store proprietary gas.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

l) Foreign currency translation

Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at period end while non-monetary assets and liabilities are translated at historical rates of exchange. Revenues and expenses are translated at monthly average rates of exchange. Translation gains and losses are reflected in net earnings or loss in the period in which they arise.

m) Borrowing costs

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in net earnings or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Corporation's outstanding long-term bank debt during the period.

n) Income tax

Income tax expense comprises current and deferred components. Income tax expense is recognized in net earnings or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the period end date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the period end date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each period end date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

o) Earnings or loss per share amounts

Basic earnings or loss per share is calculated by dividing the net earnings or loss by the weighted average number of common shares outstanding during the period. For the dilutive net earnings or loss per share calculation, the weighted average number of share outstanding is adjusted for the potential number of shares which may have a dilutive effect on net earnings or loss.

Diluted earnings or loss per share is calculated given the effect of the potential dilution that would occur if outstanding Share Options, Restricted Rights or potential dilutive convertible debentures were exercised or converted into common shares. The weighted average number of diluted shares is calculated in accordance with the treasury stock method for Share Options and Restricted Rights and the if-converted method for potentially issuable commons shares through the convertible debentures. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase common shares at the average market price. The if-converted method assumes conversion of convertible securities at the beginning of the reporting period.

From January 1, 2010 until the June 30, 2010 conversion, the Corporation included the Trust Units classified as liability in the denominator for basic and diluted per share calculations.

p) New pronouncements adopted

Accounting standards effective for periods beginning on January 1, 2011 have been adopted as part of the transition to IFRS.

q) Recent pronouncements issued

In May 2011, the IASB issued IFRS 11, Joint Arrangements, to replace International Accounting Standard ("IAS") 31, Interests in Joint Ventures, IFRS 10, Consolidated Financial Statements, IFRS 12, Disclosure of Interests in Other Entities, and IFRS 13, Fair Value Measurements, effective for years beginning on or after January 1, 2013 with earlier application permitted. IFRS 11 eliminates the accounting policy choice between proportionate consolidation and equity method accounting for joint ventures available under IAS 31 and, instead, mandates one of these two methodologies based on the economic substance of the joint arrangement. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements. IFRS 12 requires entities to disclose information about the nature of their interests in joint ventures and IFRS 13 defines, and establishes a framework for measuring, fair value.

In June 2011, the IASB issued an amendment to IAS 19, Employee Benefits, to address the accounting and disclosure of defined benefit pension plans effective for years beginning on or after January 1, 2013 with earlier application permitted.

Perpetual has not applied any of these new standards as of December 31, 2011. Perpetual continues to assess their impact and, at this time, does not anticipate any of them to result in significant accounting or disclosure changes.

4. ASSETS HELD FOR SALE

Assets and liabilities held for sale at December 31, 2011 were as follows:

Assets held for sale	
Exploration and evaluation (note 6)	4,836
Property, plant and equipment (note 5)	15,489
	20,325

Liabilities associated with assets held for sale	
Decommissioning obligations (note 15)	**4,843**

During the fourth quarter of 2011, Perpetual had announced plans to dispose of non-core assets. At December 31, 2011, assets of $20.3 million and associated liabilities of $4.8 million represent a disposal group within the Corporation's West Central and Other South CGU's and are presented as held for sale as at December 31, 2011. Further details concerning the sale of these and other assets sold in 2012 are provided in note 23.

5. PROPERTY, PLANT AND EQUIPMENT

	Oil and Gas Properties	Corporate Assets	Total
Cost			
January 1, 2010	2,338,883	4,854	2,343,737
Additions	158,120	707	158,827
Transferred from exploration and evaluation	13,730	–	13,730
Acquisitions	123,348	–	123,348
Capitalized borrowing costs	305	–	305
Dispositions	(59,618)	–	(59,618)
December 31, 2010	2,574,768	5,561	2,580,329
Additions	137,066	588	137,654
Transferred from exploration and evaluation	9,538	–	9,538
Acquisitions	7,098	–	7,098
Dispositions	(28,681)	–	(28,681)
Reclassification to assets held for sale (note 4)	(59,317)	–	(59,317)
December 31, 2011	**2,640,472**	**6,149**	**2,646,621**
Accumulated depletion, depreciation and impairment losses			
January 1, 2010	(1,468,418)	(3,163)	(1,471,581)
Depletion and depreciation	(224,284)	(738)	(225,022)
Impairment losses	(24,261)	–	(24,261)
December 31, 2010	(1,716,963)	(3,901)	(1,720,864)
Depletion and depreciation	(115,139)	(911)	(116,050)
Impairment losses	(25,607)	–	(25,607)
Reclassification to assets held for sale (note 4)	43,828	–	43,828
December 31, 2011	**(1,813,881)**	**(4,812)**	**(1,818,693)**
Carrying amount			
January 1, 2010 (note 24)	870,465	1,691	872,156
December 31, 2010 (note 24)	857,805	1,660	859,465
December 31, 2011	**826,591**	**1,337**	**827,928**

At December 31, 2011, property, plant and equipment included $4.5 million (December 31, 2010 – $4.5 million) of costs currently not subject to depletion and $23.8 million (December 31, 2010 – $23.8 million) of costs related to shut-in gas over bitumen reserves which are not being depleted due to the non-producing status of the wells in the affected properties.

During the year ended December 31, 2011, the Corporation disposed of non-core oil and natural gas properties for cash proceeds of $41.7 million (2010 – $84.2 million). Gain on dispositions totaling $12.0 million (2010 – $41.8 million) was recorded in net loss.

For the year ended December 31, 2011, the Corporation recognized impairment losses of $25.6 million on natural gas assets geographically located within the Birchwavy West and Other South CGU's (2010 – $24.3 million on Birchwavy West, West Central and Other South CGU's). The impairments resulted from the decline in forecast natural gas prices. The impairments recognized were based on the difference between the carrying amount of the CGU's (including decommissioning costs) and the value in use. In assessing value in use, the estimated future cash flows were discounted to their present value using a pre-tax discount rate of 10.0 percent (2010 – 10.0 percent). The amount in value in use is computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

On April 1, 2010, the Corporation closed an acquisition of certain petroleum and natural gas properties and related assets located in the Edson area of the Corporation's West Central CGU. The acquisition was partially financed with the proceeds of a bought deal subscription receipt financing, which closed on March 30, 2010, as well as through available credit facilities. Under the bought deal financing, Perpetual issued 12.1 million common shares at a price of $4.75 per common share for gross proceeds of $57.5 million. The remainder of the $123.3 million consideration consisted of a cash payment. Perpetual assumed $4.4 million of decommissioning obligations in the transaction. The purchase price was allocated to property, plant and equipment and E&E assets with no consideration assigned to goodwill, intangible assets or deferred tax assets or liabilities and no working capital involved in the acquisition.

6. EXPLORATION AND EVALUATION

Cost	
January 1, 2010 (note 24)	111,604
Additions	13,790
Acquisitions (note 5)	21,014
Dispositions	(15,380)
Transferred to property, plant and equipment	(13,730)
Non-cash exploration and evaluation expense	(9,824)
December 31, 2010 (note 24)	107,474
Additions	25,787
Acquisitions	609
Dispositions	(4,532)
Transferred to property, plant and equipment	(9,538)
Non-cash exploration and evaluation expense	(8,201)
Reclassification to assets held for sale (note 4)	(4,836)
December 31, 2011	**106,763**

The Corporation's E&E assets consist of undeveloped land and bitumen evaluation assets.

During the year ended December 31, 2011, $7.8 million (2010 – $8.5 million) in costs were charged directly to E&E expense in net loss.

7. GOODWILL

Goodwill was recognized as a result of the Corporation acquiring an oil and gas exploration and production company in 2004 which was assigned entirely to the Athabasca CGU. During the year ended December 31, 2011, the Corporation derecognized the remaining goodwill of $6.0 million to loss on disposition of property, plant and equipment as the Corporation disposed the remaining assets in the Athabasca CGU associated with this previous acquisition.

8. BANK DEBT

The Corporation's Credit Facility is with a syndicate of Canadian chartered banks. The revolving nature of the Credit Facility expires on May 29, 2012. Upon expiry of the revolving feature of the facility, should it not be extended, amounts outstanding as of the expiry date will have a term to maturity date of one additional year. On December 9, 2011, the Corporation completed its semi-annual review of the borrowing base with its lenders. The borrowing base was reduced from $210.0 million to $190.0 million. On March 1, 2012, the borrowing based was further reduced due to asset sales from $190.0 million to $171.0 million, consisting of a demand loan of $156.0 million and a working capital facility of $15.0 million (note 23). The next redetermination of the Corporation's borrowing base is scheduled for April 30, 2012.

The Corporation has covenants that require twelve month trailing earnings before interest, taxes and depletion and depreciation to consolidated debt and consolidated senior debt to be less than 4:0 to 1:0 and 3:0 to 1:0, respectively. Consolidated debt is defined as the sum of the Corporation's period end balance of the Credit Facility, Senior Notes and outstanding letters of credit ("consolidated debt"). Consolidated senior debt is defined as the sum of consolidated debt less the period end balance of the Senior Notes. The Corporation was in compliance with the lenders' covenants at December 31, 2011. In addition to amounts outstanding under the Credit Facility, the Corporation has outstanding letters of credit in the amount of $7.7 million (December 31, 2010 – $6.1 million). 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 in respect of amounts borrowed under the Credit Facility.

Advances under the Credit Facility are made in the form of Banker's Acceptances ("BA"), prime rate loans or letters of credit. In the case of BA advances, interest is a function of the BA rate plus a margin based on the Corporation's current ratio of debt to cash flow. In the case of prime rate loans, interest is charged at the lenders' prime rate plus margin. The effective interest rate on outstanding amounts at December 31, 2011 was 5.5 percent (December 31, 2010 – 4.2 percent).

9. SENIOR NOTES

On March 15, 2011, the Corporation issued $150.0 million in 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 have a cross-default provision with the Corporation's Credit Facility. The Corporation was in compliance with the lenders' covenants at December 31, 2011. The Senior Notes mature on March 15, 2018 and bear interest at 8.75 percent, payable semi-annually on September 15 and March 15 of each year beginning on September 15, 2011. The Corporation can redeem at a premium to face value, with equity proceeds from common share offerings, up to 35 percent of the principal amount of the Senior Notes prior to March 15, 2015. The Corporation can repay the Senior Notes at any time on or after March 15, 2015 to maturity date at a premium to face value based on date of repayment. The Senior Notes are presented net of $3.8 million in issue costs which are amortized using an effective interest rate of 9.1 percent.

10. CONVERTIBLE DEBENTURES

The Corporation's 6.50% Convertible Debentures issued on June 20, 2007 under the symbol PMT.DB.C mature on June 30, 2012, bear interest at 6.50% per annum paid semi-annually on June 30 and December 31 of each year and are subordinated to substantially all other liabilities of the Corporation including the Credit Facility and Senior Notes. The 6.50% Convertible Debentures are convertible at the option of the holder into common shares at any time prior to the maturity date at a conversion price of $14.20 per common share.

The Corporation's 7.25% convertible unsecured subordinated debentures amended on December 17, 2009 under the symbol PMT.DB.D ("7.25% Convertible Debentures") mature on January 31, 2015, bear interest at 7.25% per annum paid semi-annually on January 31 and July 31 of each year and are subordinated to substantially all other liabilities of the Corporation including the Credit Facility and Senior Notes. The 7.25% Convertible Debentures are convertible at the option of the holder into common shares at any time prior to the maturity date at a conversion price of $7.50 per common share.

The Corporation's 7.00% junior convertible unsecured subordinated debentures issued on May 26, 2010 under the symbol PMT.DB.E ("7.00% Convertible Debentures") mature on December 31, 2015, bear interest at 7.00% per annum paid semi-annually on June 30 and December 31 of each year and are subordinated to substantially all other liabilities of the Corporation including the Credit Facility, Senior Notes and all other series of convertible debentures. The 7.00% Convertible Debentures are convertible at the option of the holder into common shares at any time prior to the maturity date at a conversion price of $7.00 per common share.

At the option of the Corporation, the repayment of the principal amount of the convertible debentures may be settled in common shares. The number of common shares to be issued upon redemption by the Corporation will be calculated by dividing the principal by 95 percent of the weighted average trading price for ten trading days prior to the date of redemption. The interest payable may also be settled with the issuance of sufficient common shares to satisfy the interest obligation.

Prior to Perpetual's conversion on June 30, 2010, the convertible debentures were classified as debt on the consolidated statement of financial position with a portion of the debentures allocated to derivative debenture liability to reflect the value of the conversion option to the holders. At January 1, 2010, the derivative debenture liability was $8.4 million and was adjusted for changes in fair value at each subsequent period end date until the June 30, 2010 conversion. The derivative debenture liability of the convertible debentures was reclassified to equity upon the conversion at its June 30, 2010 carrying amount of $8.5 million. The debt component is measured at amortized cost, after initial recognition at fair value.

	Series				
	6.25%	6.50%	7.25%	7.00%	Total
	PMT.DB.B	**PMT.DB.C**	**PMT.DB.D**	**PMT.DB.E**	
Carrying amount					
Balance, January 1, 2010	55,271	71,927	92,999	–	220,197
Issue of debentures	–	–	–	60,000	60,000
Issue fees for debentures	–	–	(203)	(2,724)	(2,927)
Equity component of issued debentures	–	–	–	(5,460)	(5,460)
Accretion	–	551	885	505	1,941
Amortization of debenture issue fees	–	551	430	228	1,209
Repayment of principal on maturity	(55,271)	–	–	–	(55,271)
Long-term balance, December 31, 2010	–	73,029	94,111	52,549	219,689
Accretion	–	591	807	790	2,188
Amortization of debenture issue fees	–	630	407	356	1,393
Balance, December 31, 2011	**–**	**74,250**	**95,325**	**53,695**	**223,270**
Current	–	74,250	–	–	74,250
Long-term	–	–	95,325	53,695	149,020
Market Value					
December 31, 2010	–	75,674	101,971	60,240	237,885
December 31, 2011	**–**	**72,543**	**79,987**	**45,690**	**198,220**
Principal amount outstanding					
December 31, 2010 and December 31, 2011	**–**	**74,925**	**99,972**	**60,000**	**234,897**

11. GAS STORAGE OBLIGATION

To provide funding for the development of a natural gas storage facility, the Corporation entered into a forward sales arrangement with a counterparty, whereby the Corporation received $31.6 million on June 30, 2010 and an additional $10 million in 2011. In exchange for the funds received, the Corporation agreed to deliver 8.0 billion cubic feet of natural gas to the counterparty during the first quarter of 2013. During the year ended December 31, 2011, the maturity of the obligation was extended to the first quarter of 2016. The Corporation incurred $0.5 million in issue fees pertaining to the gas storage arrangement, which are netted against the gas storage obligation.

The gas storage obligation on the statement of financial position, in combination with the related derivative asset, 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.

For the year ended December 31, 2011, the Corporation recorded an unrealized gain of $4.1 million (2010 – $3.7 million) on the derivative gas storage asset due to the change in the forward price curves for natural gas used in the determination of the obligation to be repaid. As at December 31, 2011, the fair value of the derivative gas storage asset was $7.8 million (December 31, 2010 – $3.7 million)

A reconciliation of the gas storage obligation is provided below:

Balance, January 1, 2010	–
Receipt of funds	31,569
Issue fees	(418)
Accretion	570
Balance, December 31, 2010	31,721
Receipt of funds	10,000
Issue fees	(91)
Balance, December 31, 2011	**41,630**

12. GAS OVER BITUMEN ROYALTY OBLIGATION

On October 4, 2004, the Government of Alberta enacted amendments to the royalty regulation with respect to natural gas which provides a mechanism whereby the Government may prescribe 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 Alberta Energy and Utilities Board as a result of bitumen conservation decisions. Such royalty reduction was initially prescribed in December 2004, retroactive to the date of shut-in of the gas production.

If production recommences from zones previously ordered to be shut-in, gas producers may pay an incremental royalty to the Crown on production from the reinstated pools, along with Alberta Gas Crown Royalties otherwise payable. The incremental royalty will apply only to the pool or pools reinstated to production and will be established at one percent after the first year of shut-in increasing at one percent per annum based on the period of time such zones remained shut-in to a maximum of ten percent. The incremental royalties payable to the Crown would be limited to amounts recovered by a gas well operator through the reduced royalty.

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 are lower than the monthly royalty adjustment, and as such the royalty adjustments are not received immediately. As of December 31, 2011, the Corporation has accumulated $9.1 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 on dispositions	(13,767)
Royalty adjustments	10,454
Royalty adjustments not yet received	(3,357)
Balance, December 31, 2010	70,497
Royalty adjustments	4,772
Royalty adjustments not yet received	(564)
Balance, December 31, 2011	**74,705**

In 2006 and 2010, the Corporation disposed of certain shut-in gas wells in the gas over bitumen area. As part of the disposition agreements, the Corporation continues to receive the gas over bitumen royalty adjustments related to the wells disposed, although the ownership of the natural gas reserves was transferred to the buyers. As such, any overriding royalty payable to the Crown when gas production recommences from the affected wells is no longer the Corporation's responsibility. As a result of these dispositions, the gas over bitumen royalty adjustments received by the Corporation for the affected wells are considered revenue since they will not be repaid to the Crown. For the year ended December 31, 2011, the Corporation recognized $6.7 million (2010 – $15.6 million) in revenue respectively, related to previous gas over bitumen royalty obligations for wells disposed.

13. SHARE CAPITAL

a) Authorized

Authorized capital consists of an unlimited number of common shares.

b) Trust conversion

At January 1, 2010, the Corporation was a trust. Under IAS 32 Financial Instruments: Presentation, the redeemable feature of the trust units along with the unavoidable requirement for distributions to be paid out according to the provisions of the trust indenture required the trust units to be classified as a liability. Upon the June 30, 2010 conversion, the trust unit liability was reclassified to equity at its carrying amount.

c) Issued and outstanding

The following is a summary of changes in Unitholders' liability:

	Number of Units	Amount ($)
Balance, January 1, 2010	126,223,517	1,156,245
Trust Units issued pursuant to Restricted Rights Plan	141,760	1,012
Trust Units issued pursuant to Unit Incentive Plan	114,625	654
Trust Units issued pursuant to Distribution Reinvestment Plan	5,033,838	23,784
Trust Units issued pursuant to Unit offering	12,109,500	57,520
Issue fees incurred	–	(3,199)
Transfer to share capital upon conversion	(143,623,240)	(1,236,016)
Balance, June 30, 2010	–	–

The following is a summary of changes in share capital:

	Number of Units	Amount ($)
Balance, June 30, 2010	–	–
Transfer from Unitholders' liability upon conversion	143,623,240	1,236,016
Common Shares issued pursuant to Restricted Rights Plan	27,802	175
Common Shares issued pursuant to Share Option Plan	76,145	515
Common Shares issued pursuant to Premium Dividend Reinvestment Plan	4,270,007	19,535
Common Shares issued pursuant to Severo acquisition	287,086	1,479
Issue fees incurred	–	(258)
Balance, December 31, 2010	148,284,280	1,257,462
Common shares issued pursuant to Restricted Rights Plan	246,766	1,043
Common shares issued pursuant to Share Option Plan	46,313	494
Common shares repurchased	(1,611,100)	(4,718)
Issue fees incurred	–	(8)
Balance, December 31, 2011	**146,966,259**	**1,254,273**

d) Per share information

For the year ended December 31, 2011, basic per share amounts are calculated using the weighted average number of common shares outstanding of 147,693,782 (2010 – 140,623,543). From January 1, 2010 until the June 30, 2010 conversion, the Corporation included the Trust Units classified as liability in the denominator for basic and diluted per share calculations. The Corporation uses the treasury stock method for Share Options and Restricted Rights in instances where market price exceeds exercise price thereby impacting the diluted calculations. The Corporation uses the if-converted method for potentially issuable commons shares through the convertible debentures. In computing diluted per share amounts for the year ended December 31, 2011, nil common shares were added to the basic weighted average number of common shares outstanding (2010 – nil) for the dilutive effect of Share Options, Restricted Rights and convertible debentures. In computing diluted per share amounts for the year ended December 31, 2011, 12,297,100 Share Options, 1,365,107 Restricted Rights, 276,200 Performance Share Rights and 27,177,437 potentially issuable common shares through the convertible debentures were excluded as the Corporation had a net loss (2010 – 12,075,300, 250,102 and nil Share Options, Restricted Rights and Performance Share Rights respectively and 27,177,437 potentially issuable through the convertible debentures).

e) Dividends

Dividends of $0.03 per common share per month were declared by the Corporation for the months of January through April, 2011. The Corporation announced a reduction to the dividend to $0.015 per common share per month for the months of May through September 2011. Total dividends declared for the year ended December 31, 2011 were $28.9 million. For the year ended December 31, 2010, the Corporation declared distributions of $0.05 per Trust unit/common share per month for the months of January through October 2010 followed by a reduction to $0.03 per Trust unit/common share per month for the months of November and December 2010 for total distributions declared of $78.6 million consisting of $40.5 million in interest on Trust Units prior to Perpetual's conversion to a corporation on June 30, 2010 and $38.1 million in dividends post conversion.

On October 19, 2011 the Corporation announced that future dividend payments would be suspended until further notice.

14. SHARE BASED PAYMENTS

a) Share Option Plan

In conjunction with the conversion on June 30, 2010, the Corporation replaced the previous Unit Incentive Plan with the Share Option Plan, which permits the Board of Directors to grant Share Options to the Corporation and affiliated entities' employees, officers, directors and other direct and indirect service providers. All outstanding Incentive Rights were replaced with Share Options on a one for one basis, with the same exercise price and vesting conditions. The purpose of the Share Option Plan is to provide an effective long-term incentive to eligible participants and to reward them on the basis of the Corporation's long-term performance. The Board of Directors administers the Share Option Plan and determines participants, numbers of Share Options and terms of vesting. The exercise price of the Share Options shall not be less than the value of the weighted average trading price for Perpetual common shares for the five trading days immediately preceding the date of the grant.

Prior to the June 30, 2010 implementation of the Share Option Plan, the Unit Incentive Plan provided for a reduction of the exercise price of the Incentive Rights by the aggregate amounts of all distributions on a per Trust Unit basis that the Trust paid its Unitholders after the date of grant. This exercise price reduction was discontinued at the time of the implementation of the Share Option Plan. Prior to the conversion, the Unit Incentive Plan was accounted for as a cash-settled plan. Unit Incentive Rights outstanding under the Unit Incentive Plan were fair valued at each period end date, with changes in the fair value being recognized in net earnings or loss as shared based compensation within general and administrative expense.

Share Options outstanding under the Share Option Plan are accounted for as equity-settled awards fair valued at the grant date and expensed over the expected lives of the options. The participants of the Share Option Plan may offer to surrender their options to the Corporation in exchange for a cash payment not to exceed the in-the-money value of the Share Options, and the Corporation has the right to accept or refuse such offers. For the year ended December 31, 2011 the Corporation recorded $3.7 million in share based payment expense related to Share Options (2010 – $1.9 million).

At December 31, 2011, the Corporation had 13.7 million Share Options and Restricted Rights (December 31, 2010 – 12.3 million) issued and outstanding relative to the 14.7 million (ten percent of total common shares outstanding) reserved under the Share Option and Restricted Rights Plans (December 31, 2010 – 14.8 million). As at December 31, 2011, 4.2 million Share Options granted under the Share Option Plan had vested but were unexercised (December 31, 2010 – 2.5 million).

The Corporation used the binomial lattice option pricing model to calculate the estimated fair value of the outstanding Share Options. During the year ended December 31, 2011, the Corporation granted 2.9 million Share Options under the Share Option Plan. The following assumptions were used to arrive at the estimate of fair value as at the date of grant:

Period of grant	**2011**	2010
Dividend yield (%)	**0.0 – 5.9**	0.0 – 11.9
Forfeiture rate (%)	**2.6 – 8.0**	0.0 – 3.2
Expected volatility (%)	**41.2 – 50.6**	46.7 – 49.9
Risk-free interest rate (%)	**0.9 – 2.2**	1.7 – 2.3
Expected life (years)	**2.5 – 4.5**	3.0 – 3.8
Vesting period (years)	**3.0 – 4.0**	3.0 – 4.0
Contractual life (years)	**4.0 – 5.0**	4.0 – 5.0
Weighted average grant date fair value	**$ 0.58**	$ 0.98

	Average Exercise Price	Share Options[1]
Balance, December 31, 2009	$ 4.72	8,861,850
Granted	4.78	4,515,450
Forfeited	4.84	(1,111,230)
Exercised	3.68	(190,770)
Balance, December 31, 2010	4.55	12,075,300
Granted	2.14	2,858,300
Forfeited	4.62	(2,381,375)
Exercised	2.09	(255,125)
Balance, December 31, 2011	**$ 4.00**	**12,297,100**

(1) On June 30, 2010, the Corporation's outstanding Unit Incentive Rights were exchanged for Perpetual Share Options on a one-for-one basis and equivalent terms.

The following table summarizes information about Share Options outstanding at December 31, 2011:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number (#)	Average Contractual Life (years)	Weighted Average Exercise Price ($)	Number (#)	Weighted Average Exercise Price ($)
$1.19 to $2.44	1,481,700	3.97	1.26	–	–
$2.45 to $4.49	5,999,650	2.59	3.54	2,435,506	3.64
$4.50 to $6.99	4,226,500	2.63	4.96	1,215,583	5.12
$7.00 to $8.99	183,500	0.82	7.47	169,250	7.40
$9.00 to $11.00	405,750	0.44	9.13	405,750	9.13
Total	**12,297,100**	**2.67**	**4.00**	**4,226,089**	**4.74**

b) Restricted rights plan

The Corporation has a Restricted Rights Plan for certain officers, employees and direct and indirect service providers. Restricted Rights granted under the Restricted Rights Plan may be exercised during a period (the "Exercise Period") not exceeding five years from the date upon which the Restricted Rights were granted. The Restricted Rights typically vest on a graded basis over two years. At the expiration of the Exercise Period, any Restricted Rights which have not been exercised shall expire and become null and void. Upon vesting, the plan participant is entitled to receive the vested common shares at no cost plus an additional number of common shares equal to the value of dividends on the Corporation's shares as if the shares were invested in the Premium Dividend Reinvestment Plan accrued since the grant date.

For the year ended December 31, 2011, $1.8 million in share based payments were recorded in respect of Restricted Rights (2010 – $0.9 million).

The following table shows changes in the Restricted Rights outstanding under the Restricted Rights Plan:

Balance, January 1, 2010	288,629
Exercised	(169,564)
Granted	106,067
Forfeited	(7,112)
Additional grants for accrued Dividends	32,082
Balance, December 31, 2010	250,102
Exercised	(250,433)
Granted	1,389,348
Forfeited	(55,385)
Additional grants for accrued Dividends	31,475
Balance, December 31, 2011	**1,365,107**

c) Performance share rights plan

The Corporation has a Performance Share Rights Plan for the Corporations senior management team. Performance Share Rights granted under the Performance Share Rights Plan may be exercised two years after the date upon which the Performance Share Rights were granted. The Performance Share Rights vest on a graded basis over two years. The amount of Performance Share Rights that vest is a multiple of the Performance Share Rights granted contingent upon the achievement of certain performance metrics over the vesting period. Vested Performance Share Rights can be settled in cash or Restricted Rights, at the discretion of the Board of Directors. Upon vesting, Performance Share Rights Plan participants are entitled to receive an additional number of Performance Share Rights equal to the value of dividends on the Corporation's shares as if the shares were invested in the Premium Dividend Reinvestment Plan accrued since the grant date. Should participants of the Performance Share Rights Plan leave the organization other than through retirement or termination without cause prior to the vesting date, the Performance Share Rights would be forfeited.

At December 31, 2011, the Corporation had 276,200 Performance Share Rights issued and outstanding under the Performance Share Rights Plan (December 31, 2010 – nil).

For the year ended December 31, 2011, $0.1 million in share based payments were recorded in respect of the Performance Share Rights granted (2010 – nil).

d) Dividend bonus agreement

On July 17, 2010, the Corporation introduced a Dividend Bonus Arrangement, which provides for participants in the Share Option Plan to receive a payment in cash or Restricted Rights, at the discretion of the Board of Directors, upon the exercise, surrender or expiry of vested options. The amount of dividend bonus is based on aggregate dividends accumulated commencing with the July 2010 dividend. Plan participants are entitled to 25 percent of such aggregate dividend for vested options which expire out of the money. The Dividend Bonus Arrangement is accounted for as a cash-settled plan. The fair value of this liability has been estimated by calculating the net present value of the dividend streams that would come into effect under different share prices at estimated exercise and expiry dates. These discounted dividend streams are then multiplied by the probability of prices being within a certain range. A liability of $0.7 million has been calculated as at December 31, 2011 (December 31, 2010 – $2.1 million) to reflect the value outstanding under the Dividend Bonus Arrangement.

15. DECOMMISSIONING OBLIGATIONS

The total future asset decommissioning obligations are estimated based on the Corporation's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future periods.

The Corporation adjusts the decommissioning obligations on each period end date for changes in the risk free rate. Accretion is calculated on the adjusted balance after taking into account additions and dispositions to property, plant, and equipment. Decommissioning obligations are also adjusted annually for revisions to the future liability cost and the estimated timing of costs to be incurred in future years.

The Corporation has estimated the net present value of its total decommissioning obligations to be $247.7 million as at December 31, 2011 (December 31, 2010 – $236.2 million) based on an undiscounted inflation-adjusted total future liability of $326.3 million (December 31, 2010 – $349.6 million). These payments are expected to be made over the next 25 years with the majority of costs incurred between 2015 and 2025. At December 31, 2011, the Corporation used an average risk free rate of 2.6 percent (December 31, 2010 – 2.7 percent) to calculate the present value of the decommissioning obligations.

The following table reconciles the Corporation's decommissioning obligations:

Balance at January 1, 2010	253,344
Obligations acquired	12,996
Obligations incurred	2,725
Obligations disposed	(33,259)
Change in risk free rate	18,232
Change in estimates	(20,643)
Obligations settled	(4,880)
Accretion	7,648
Balance at December 31, 2010 (note 24)	236,163
Obligations acquired	474
Obligations incurred	4,922
Obligations disposed	(9,587)
Change in risk free rate	16,268
Change in estimates	(5,314)
Obligations settled	(2,514)
Accretion	7,291
Reclassification to liabilities associated with assets held for sale (note 4)	(4,843)
Balance at December 31, 2011	**242,860**

16. NON-CASH WORKING CAPITAL INFORMATION

	Years ended December 31,	
	2011	2010
Accounts receivable	**(145)**	(1,380)
Prepaid expenses and deposits	**1,137**	7,882
Accounts payable and accrued liabilities	**(23,575)**	32,257
Dividends payable	**(4,449)**	(1,860)
Change in non-cash working capital	**(27,032)**	36,899

The change in non-cash working capital has been allocated to the following activities:

	Years ended December 31,	
	2011	2010
Operating	**(9,563)**	15,228
Financing	**(6,904)**	2,107
Investing	**(10,565)**	19,564
Change in non-cash working capital	**(27,032)**	36,899

17. FINANCIAL RISK MANAGEMENT

The Corporation has exposure to credit risk, liquidity risk and market risk from its use of financial instruments.

This note presents information about the Corporation's exposure to each of the above risks, the Corporation's objectives, policies and processes for measuring and managing risk, and the Corporation's management of capital. Further quantitative disclosures are included throughout these annual consolidated financial statements.

The Board of Directors has overall responsibility for the establishment and oversight of the Corporation's risk management framework. The Board of Directors has implemented and monitors compliance with risk management policies.

The Corporation's risk management policies are established to identify and analyze the risks faced by Perpetual, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Corporation's activities.

a) Credit risk

Credit risk is the risk of financial loss to the Corporation if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Corporation's receivables from joint venture partners, oil and natural gas marketers and derivative contract counterparties.

Receivables from oil and natural gas marketers are normally collected on the 25th day of the month following production. The Corporation's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large, well established purchasers. The Corporation historically has not experienced any significant collection issues with its oil and natural gas marketing receivables. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Corporation attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, the receivables are generally from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs, the risk of unsuccessful drilling and oil and gas production; in addition, further risk exists with joint venture partners as disagreements occasionally arise that increase the potential for non-collection. The Corporation does not typically obtain collateral from oil and natural gas marketers or joint venture partners, however, the Corporation does have the ability in some cases to withhold production or amounts payable to joint venture partners in the event of non-payment.

The Corporation manages the credit exposure related to marketable securities by monitoring the performance and financial strength of the investments and the liquidity of the securities being held.

The Corporation manages the credit exposure related to derivatives by engaging in economic hedging transactions with counterparties with investment grade credit ratings, and periodically monitoring the changes in such credit ratings.

During the year ended December 31, 2011, credit risk did not have any impact on the change in fair value of financial assets and liabilities classified as fair value through profit or loss.

The carrying amount of accounts receivable, marketable securities and fair value of derivatives represents the Corporation's maximum credit exposure. The Corporation's allowance for doubtful accounts as at December 31, 2011 is $0.6 million (December 31, 2010 – $0.1 million). The amount of the allowance was determined by assessing the probability of collection for each past due receivable. The Corporation is currently involved in negotiations with the joint venture partners involved to recover the full amount of the receivables in question. The total amount of accounts receivables 90 days past due amounted to $3.9 million as at December 31, 2011 (December 31, 2010 – $2.3 million). As at December 31, 2011, as a partial mitigating factor to the credit exposure, the Corporation has $1.9 million (December 31, 2010 – $0.8 million) payable to counterparties from which the Corporation holds 90 days past due receivables.

b) Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they are due. The Corporation's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking harm to the Corporation's reputation.

The Corporation prepares annual capital expenditure budgets which are regularly monitored and updated as considered necessary. Further, the Corporation utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. To facilitate the capital expenditure program, the Corporation has a Credit Facility, as outlined in note 8. The Corporation's Credit Facility and borrowing base are subject to review by its lenders on a semi-annual basis.

The following are the contractual maturities of financial liabilities and associated interest payments as at December 31, 2011:

Contractual repayments of financial liabilities	**Total**	2012	2013	2014-2016	Thereafter
Accounts payable and accrued liabilities	**50,404**	50,404	–	–	–
Derivative liability	**17,706**	6,841	3,064	7,801	–
Long-term bank debt – principal (1)	**130,062**	–	130,062	–	–
Senior notes – principal	**150,000**	–	–	–	150,000
Convertible debentures – principal (2)	**234,897**	74,925	–	159,972	–
Gas storage obligation	**41,630**	–	–	41,630	–
Total	**624,699**	132,170	133,126	209,403	150,000

(1) The revolving feature of the Credit Facility expires on May 29, 2012 if not extended. Upon expiry of the revolving feature of the Credit Facility, should it not be extended, amounts outstanding as of the expiry date will have a term to maturity date of one additional year.

(2) Assuming repayment of principal is not settled in common shares, at the option of the Corporation.

Interest payments on financial liabilities	Total	2012	2013	2014-2016	Thereafter
Long-term bank debt(1)	**10,133**	7,153	2,980	–	–
Senior notes	**81,411**	13,125	13,125	39,375	15,786
Convertible debentures (2)	**41,595**	13,883	11,448	16,264	–
Total	**133,139**	34,161	27,553	55,639	15,786

(1) Assuming revolving feature of the Credit Facility is not extended and calculated at the December 31, 2011 effective interest rate of 5.5% assuming a constant debt level equivalent to the balance at December 31, 2011.

(2) Assuming payment of interest is not settled in common shares at the option of the Corporation.

c) Market risk

Market risk is the risk that changes in market prices such as foreign exchange rates, equity prices, commodity prices and interest rates will affect the Corporation's net earnings or loss or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Corporation utilizes both financial derivatives and fixed-price physical delivery sales contracts to manage market risks related to commodity prices and currency rates. All such transactions are conducted in accordance with the Corporation's Hedging and Risk Management Policy, which has been approved by the Board of Directors.

i) Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows of the Corporation will fluctuate as a result of changes in foreign exchange rates. The majority of the Corporation's oil and natural gas sales are denominated in Canadian dollars. Due to the fact that the demand for oil and natural gas is substantially driven by the demand in the United States, the Corporation's exposure to US dollar foreign exchange risk is indirectly driven by the price of oil and natural gas. From time to time the Corporation also uses foreign exchange contracts to mitigate the effects of fluctuations in exchange rates on the Corporation's cash flows. The Corporation does not consider its direct exposure to foreign currency exchange rate risk to be significant; refer to commodity price risk analysis below.

ii) Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by the world economic events that dictate the levels of supply and demand. The Corporation has attempted to mitigate commodity price risk through the use of various financial derivative and physical delivery sales contracts. The Corporation's policy is to enter into financial and forward physical gas sales contracts up to a maximum of 60 percent of the trailing quarter's production including gas over bitumen deemed production, as outlined in the Corporation's Hedging and Risk Management Policy.

As at December 31, 2011, the Corporation has variable priced physical natural gas sales contracts based on future market prices. These contracts are not classified as non-financial derivatives due to the fact that the settlement price corresponds directly with fluctuations in natural gas prices.

Realized gains on commodity price derivatives recognized in net loss for the year ended December 31, 2011 were $2.2 million (2010 – $155.0 million). The realized gains on commodity price derivatives for the year ended December 31, 2011, included nil in respect of settlement of contracts prior to maturity (2010 – $134.2 million).

Natural gas contracts

At December 31, 2011, the Corporation had entered into forward gas sales arrangements at AECO as follows:

Type of Contract	Perpetual Sold/Bought	Volumes at AECO (GJ/d)	Price ($/GJ)	Term
Financial	sold	60,000	$3.21	January 2012
Financial	bought	(46,365)	$3.00	January 2012
Financial (1)	sold	30,000	$3.63	January 2012 – December 2012
Financial (2)	sold	15,250	$3.90	January 2012 – December 2012
Financial	sold	10,000	$2.85	April 2012 – October 2012
Financial	sold	7,500	$3.60	January 2013 – December 2013

(1) These derivative transactions are part of paired transactions in which the proceeds from the sale of 2014 oil call options were used to fund the 2012 natural gas contract at the price indicated.

(2) This derivative transaction is part of paired transaction in which the proceeds from the sale of a December 31, 2011 oil swaption were used to fund the 2012 natural gas contract at the price indicated.

At December 31, 2011, the Corporation had entered into forward gas sales arrangements at NYMEX as follows:

Type of Contract	Perpetual Sold/Bought	Volumes at AECO (MMBTU/d)	Price ($/MMBTU)	Term
Financial	sold	50,000	$3.51	January 2012
Financial	sold	25,000	$3.00	February 2012

At December 31, 2011, the Corporation had entered into financial forward gas sales arrangements to fix the basis differential between the NYMEX and AECO trading hubs as follows. The price at which these contracts settle is equal to the NYMEX index less a fixed basis amount.

Type of Contract	Perpetual Sold/Bought	Volumes at NYMEX (MMBTU/d)	Price (US$/MMBTU)	Term
Financial	sold	50,000	($0.46)	January 2012 – March 2012
Financial	bought	(12,500)	($0.60)	April 2012 – October 2012
Financial	sold	62,500	($0.57)	April 2012 – October 2012

Oil contracts

At December 31, 2011, the Corporation had entered into a financial and forward physical oil sales arrangement to fix the basis differential between the WTI and WCS 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 2012 – December 2012

At December 31, 2011 the Corporation had entered into the following costless collar oil sales arrangements:

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

At December 31, 2011, the Corporation had entered into financial call option oil sales arrangements, whereby the Corporation's counterparty has the right to settle specified volumes of oil at specified prices in the future periods. Any subsequent changes in the fair values of the call options are included in change in fair values of commodity derivatives in net loss.

Type of Contract	Perpetual Sold/Bought	Volumes at WTI (bbls/d)	Price (US$/bbls)	Term
Financial	sold	1,000	$105.00	January 2013 – December 2013
Financial (1)	sold	1,000	$105.00	January 2014 – December 2014
Financial (1)	sold	1,000	$105.00	January 2014 – December 2014

(1) These oil call options are part of paired transactions in which the proceeds from the sale of the call options were used to fund the 2012 natural gas contract price.

The Corporation has entered into a financial oil call swaption, whereby the Corporation's counterparty has the right to exercise the call option on December 31, 2012 or it expires. If exercised, the Corporation will be entered into a forward oil sales arrangement for 1,000 bbls/d at a WTI price of US$95.00/bbls for a term of January 2013 – December 2013.

Power contracts

At December 31, 2011, the Corporation had entered into the following forward financial contracts to mitigate the risk associated with fluctuations in power prices:

Type of Contract	Perpetual Sold/Bought	Volume (MWh)	Price (CAD$/MWh)	Term
Financial	bought	(2,745.36)	$49.60	January 2012
Financial	bought	(2,157.60)	$49.60	February 2012
Financial	bought	(2,209.68)	$49.60	March 2012
Financial	bought	(4,516.08)	$72.39	January 2012
Financial	bought	(3,793.20)	$72.39	February 2012
Financial	bought	(2,923.92)	$72.39	March 2012
Financial	bought	(6,480.00)	$76.00	January 2013 – March 2013

Foreign exchange contracts

At December 31, 2011, the Corporation had entered into the following $US 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)	$1.0019	January 2012 – December 2012
Financial	bought	($1,000,000)	$1.0085	January 2012 – December 2012
Financial	bought	($1,000,000)	$1.0125	January 2012 – December 2012
Financial	bought	($2,000,000)	$1.0535	January 2012 – December 2012

The following table reconciles the Corporation's derivative assets and liabilities:

	Current	Non Current	Total
Balance, January 1, 2010	46,152	21,167	67,319
Unrealized gain on gas storage obligation derivative	–	3,729	3,729
Unrealized loss on forward natural gas contracts	(41,881)	(21,334)	(63,215)
Balance, December 31, 2010	4,271	3,562	7,833
Unrealized gain on gas storage obligation derivative	–	4,117	4,117
Unrealized gain on natural gas and oil contracts	4,983	531	5,514
Unrealized loss financial oil call swaption	(4,242)	–	(4,242)
Unrealized loss on oil call options	–	(11,396)	(11,396)
Unrealized gain on power contracts	424	13	437
Unrealized gain on forward foreign exchange contracts	327	–	327
Balance, December 31, 2011	**5,763**	**(3,173)**	**2,590**
Assets	12,604	7,692	20,296
Liabilities	(6,841)	(10,865)	(17,706)
Balance, December 31, 2011	**5,763**	**(3,173)**	**2,590**

The following table reconciles the Corporation's change in fair value of commodity derivatives:

	Years ended December 31,	
	2011	2010
Realized gain on natural gas and oil contracts	**2,217**	155,025
Call option premiums received	**3,124**	1,851
Unrealized gain (loss) on natural gas and oil contracts	**5,514**	(63,215)
Unrealized loss financial oil call swaption	**(4,242)**	–
Unrealized loss on oil call options	**(11,396)**	–
Unrealized gain on power contracts	**437**	–
Unrealized gain on forward foreign exchange contracts	**327**	–
	(4,019)	93,661

Commodity and currency price sensitivity analysis

As at December 31, 2011, if future natural gas prices changed by \$0.25 per GJ for AECO contracts and \$0.25 per MMBTU for NYMEX contracts, with all other variables held constant, the fair value of commodity price derivatives and after tax net loss for the period would have changed by \$3.0 million. Fair value sensitivity was based on published forward AECO and NYMEX prices. Gains and losses on NYMEX contracts were calculated based on the \$US foreign exchange rate as at December 31, 2011.

As at December 31, 2011, if the \$US to \$CAD foreign exchange rate changed by \$0.025 for foreign exchange contracts, with all other variables held constant, the fair value of currency price derivatives and after tax net loss for the period would have changed by \$1.2 million.

iii) Interest rate risk

The Corporation utilizes a Credit Facility which bears a floating rate of interest and as such is subject to interest rate risk. Increased future interest rates will decrease future cash flows and net earnings or loss, thereby potentially affecting the Corporation's future dividends and capital investments.

The Corporation's Senior Notes and convertible debentures were issued at a fixed interest rate and as such the debentures are not materially impacted by market interest rate fluctuations. To ensure accounts payable, accrued liabilities and dividends payable are settled on a timely basis, the Corporation manages liquidity risk as previously outlined in this note, thus limiting exposure to interest rate fluctuations and other penalties potentially resulting from past due payables.

The Corporation had no interest rate swap or financial contracts in place as at or during the year ended December 31, 2011 (December 31, 2010 – nil).

Interest rate sensitivity analysis

For the year ended December 31, 2011, if interest rates had been one percent lower or higher the impact on net loss would be as follows:

Interest rate sensitivity (\$ thousands)	1% increase	1% decrease
(Increase) decrease in net loss	(1,094)	1,094

The impact on net loss as a result of interest rate fluctuations is based on the assumption that the lender increases or decreases the fixed term BA rate consistently, based on a market interest rate change of one percent.

d) Fair value of financial assets and liabilities

Fair value measurements are required to be classified into one of the following levels of the fair value hierarchy:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets and liabilities.

Level 2 – Inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3 – Inputs for the asset or liability that are not based on observable market data.

The fair value of accounts receivable, accounts payable and accrued liabilities and dividends payable approximate their carrying amounts due to their short terms to maturity.

The fair value of the gas storage obligation is captured through the recording of a derivative asset or liability based on changes in the forward price curve for natural gas.

Bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying amount.

The fair values of marketable securities and convertible debentures are based on Level 1, in reference to IFRS requirements, and as such these fair values are derived from exchange traded values in active markets as at the period end date.

The fair values of derivative contracts and the gas storage obligation are based on Level 2, in reference to IFRS requirements, and as such these fair values are derived from the difference between the fixed contract price or fixed basis differential and readily observable estimated, external forward market price curves as at the period end date, based on natural gas and power volumes in executed contracts.

The fair value of the Senior Notes are based on Level 2 and is calculated based on the present value of future principal and interest cash flows, discounted at the market rate of interest on the period end date of similar note offerings.

The fair value of financial assets and liabilities were as follows:

	December 31, 2011		December 31, 2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Financial assets:				
Loans and receivables at amortized cost				
Accounts receivable	**35,604**	**35,604**	35,459	35,459
Fair value through profit and loss				
Marketable securities	**3,282**	**3,282**	6,007	6,007
Derivatives	**20,296**	**20,296**	7,833	7,833
Financial liabilities:				
Financial liabilities at amortized cost				
Accounts payable and accrued liabilities	**50,404**	**50,404**	73,979	73,979
Dividends payable	**–**	**–**	4,449	4,449
Derivatives	**17,706**	**17,706**	–	–
Long-term bank debt	**130,062**	**130,062**	182,612	182,612
Senior notes	**146,634**	**140,250**	–	–
Convertible debentures	**223,270**	**198,220**	219,689	237,885
Gas storage obligation	**41,630**	**41,630**	31,721	31,721

18. CAPITAL MANAGEMENT

The Corporation's policy is to maintain a strong capital base so as to retain investor, creditor and market confidence and to sustain the future development of the business. The Corporation manages its capital structure and makes adjustments in light of changes in economic conditions and the risk characteristics its underlying oil and natural gas assets. The Corporation considers its capital structure to include share capital, bank debt, Senior Notes, convertible debentures and adjusted working capital. In order to maintain or adjust the capital structure, the Corporation may from time to time issue shares or debt securities and adjust its capital spending to manage current and projected debt levels.

The Corporation monitors capital based on the ratio of net debt to trailing twelve months funds flow, calculated as follows for the year ended December 31, 2011:

Bank debt	130,062
Senior notes, measured at principal amount	150,000
Convertible debentures, measured at principal amount	234,897
Adjusted working capital deficiency (3)	7,627
Net debt (1)	**522,586**
Cash flow provided by operating activities	60,428
Exploration and evaluation costs (4)	3,917
Expenditures on decommissioning obligations	2,514
Gas over bitumen royalty adjustments not yet received	564
Changes in non-cash operating working capital	9,563
Trailing twelve months funds flow (2)	**76,986**
Net debt to annualized funds flow ratio (times) (1,2,5)	**6.8:1**

As at December 31, 2011, the Corporation's ratio of net debt to funds flow was 6.8 to 1. This ratio is monitored continuously by the Corporation, and the targeted range of net debt to funds flow varies based on such factors as: acquisitions, commodity prices, forecasts of future commodity prices, price management contracts, projected cash flows, dividends, capital expenditure programs and timing of such programs. As a part of the management of this ratio, the Corporation prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. Capital spending budgets are approved by the Board of Directors.

The Corporation's share capital, convertible debentures and adjusted working capital are not subject to external restrictions. The Corporation's Credit Facility and Senior Notes are subject to lenders' covenants with which the Corporation was in compliance at December 31, 2011.

The capital structure at December 31, 2011 was as follows:

Bank debt	130,062
Senior notes, measured at principal amount	150,000
Convertible debentures, measured at principal amount	234,897
Adjusted working capital deficiency (3)	7,627
Net debt (1)	**522,586**
Total equity (net of deficit)	81,558
Total capital	**604,144**

(1) Net debt is used by management to analyze leverage. Net debt does not have any standardized meaning prescribed by IFRS and therefore these terms may not be comparable with the calculation of similar measures for other entities.

(2) Management uses funds flow from operations before changes in non-cash working capital ("funds flow"), funds flow per common share and annualized funds flow to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by IFRS 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 cash flow or 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 IFRS.

(3) Adjusted working capital deficiency excludes assets held for sale, liabilities associated with assets held for sale, the share based payment liability, current portion of convertible debentures, and the current portion of derivative assets.

(4) 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 and evaluation costs that are added back to funds flow include geological and geophysical expenditures and dry hole expenditures and are more closely related to investing activities than operating activities.

(5) Net debt to annualized funds flow ratio is not comparable with the calculation of the Corporations debt covenant ratios of twelve months trailing earnings before interest, taxes, and depletion and depreciation to consolidated debt and consolidated senior debt.

19. COMMITMENTS

a) Operating lease commitments

As of December 31, 2011, the future minimum payments under office lease costs and related sublease recoveries under contractual agreements consisted of:

2012	2,275
2013	2,015
2014	1,959
2015	1,959
2016	1,959
After 2017	2,449
Total	**12,616**

b) Pipeline commitments

The Corporation has long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada. As of December 31, 2011, the future minimum payments under pipeline commitments under contractual agreements consisted of:

2012	8,451
2013	4,900
2014	2,095
2015	527
2016	36
After 2017	70
Total	**16,079**

20. DEFERRED INCOME TAXES

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Corporation's loss before income tax. This difference results from the following items:

		Years ended December 31,
	2011	2010
Loss before income tax, including non-controlling interests	**(94,289)**	(98,597)
Combined federal and provincial tax rate (%)	**26.5**	28.0
Computed income tax benefit	**(24,987)**	(27,607)
Increase in income taxes resulting from:		
Non-deductible expenses	**3,079**	1,479
Unrecognized tax asset	**23,172**	5,516
Change in tax rate	**367**	22,734
Deferred income taxes	**1,631**	2,122

Income tax rates changed from 28.0 percent in 2010 to 26.5 percent in 2011 due to a reduction in federal statutory income tax rates.

The components of the Corporation's and its subsidiaries' deferred income tax liabilities are as follows:

		Years ended December 31,
	2011	2010
Property, plant and equipment	**58,493**	46,709
Other	**3,688**	5,513
Decommissioning obligations	**(58,428)**	(50,100)
	3,753	2,122

The temporary deductible differences included in the Corporation's unrecognized deferred income tax assets are as follows:

		Years ended December 31,
	2011	2010
Non-capital losses	**169,007**	58,980
Capital losses	**219,174**	218,715
Gas over bitumen royalty obligation	**73,415**	70,497
Decommissioning obligation	**13,989**	35,764
Other	**4,452**	1,827
	480,037	385,783

The tax losses expire up to 2031. The deductible temporary differences do not expire under current tax legislation. Deferred tax assets have not been recognized in respect of the tax losses and the gas over bitumen royalty obligation because it is not probable that future taxable profit will be available against which the Corporation can utilize the benefits. The petroleum and natural gas properties and facilities owned by the Corporation and its subsidiaries have an approximate tax basis of $888.0 million (December 31, 2010 – $843.0 million) available for future use as deductions from taxable income.

21. RELATED PARTIES

a) Subsidiaries

The consolidated financial statements of the Corporation include the accounts of the Corporation and its following directly wholly-owned subsidiaries incorporated in Canada:

- Perpetual Energy Operating Corp.
- Warwick Gas Storage Inc.
- Perpetual Operating Trust

b) Key management personnel

The Corporation has defined key management personnel as executive officers and vice presidents, as well as the Board of Directors, as they have the collective authority and responsibility for planning, directing and controlling the activities of the Corporation. The following table outlines the total compensation expense for key management personnel:

	Years ended December 31,	
	2011	2010
Short-term fees and other short-term benefits	**2,717**	2,464
Share-based payment expense	**2,189**	2,058
	4,906	4,522

22. SUPPLEMENTAL DISCLOSURE

The Corporation's consolidated statements of loss and comprehensive loss are prepared primarily by nature of expense, with the exception of employee compensation costs which are included in both production and operating and general and administrative expenses.

The following table details the amount of total employee compensation costs included in production and operating and general and administrative expenses in the consolidated statements of loss and comprehensive loss.

	Years ended December 31,	
	2011	2010
Production and operating	**10,193**	10,122
General and administrative	**29,428**	29,396
	39,621	39,518

During the year ended December 31, 2011, total employee compensation costs included share based payment expense of $5.6 million (2010 – $5.3 million) with the remainder being short-term fees and other short-term benefits.

23. SUBSEQUENT EVENTS

During the first quarter of 2012, The Corporation disposed of multiple non-core oil and natural gas properties geographically located in the Corporations West Central and Other South CGU's for net proceeds of $60.9 million of which $23.9 million related to assets classified as held for sale at December 31, 2011 (note 4). On March 1, 2012, the sale of these assets resulted in a reduction to the borrowing base of the Credit Facility from $190.0 million to $171.0 million (note 8). In addition, the Corporation is currently in negotiations with respect to the sale of all or a portion of its Warwick gas storage facility. The sales of these assets are in response to the Corporations asset disposition program.

24. FIRST TIME ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

The accounting policies in note 3 have been applied in preparing the consolidated financial statements for the year ended December 31, 2010, the statement of financial position as at December 31, 2010 and the preparation of an opening IFRS statement of financial position on January 1, 2010.

In preparing the consolidated financial statements for the year ended December 31, 2010, the statement of financial position as at December 31, 2010 and the preparation of an opening IFRS statement of financial position on January 1, 2010, balances have been adjusted from the amounts reported previously in the consolidated financial statements prepared in accordance with Canadian GAAP.

An explanation of how the transition from Canadian GAAP to IFRS has affected the Corporation's financial position, financial performance and cash flows is set out in the following notes.

Key first time adoption exemptions applied

i) 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 January 1, 2010. 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, E&E assets, leases and provisions.

ii) Borrowing costs

The Corporation elected to apply IAS 23 borrowing costs and capitalized borrowing costs from an effective date of August 1, 2009, the first day of construction of the Warwick gas storage facility. Borrowing costs associated with this facility and certain other developments after August 1, 2009 have been capitalized.

iii) 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.

iv) Leases

The Corporation has not reassessed any arrangements to determine whether they contain a lease if they have already been assessed under Canadian GAAP. Additionally, any arrangements that have not been assessed under Canadian GAAP have been assessed under IFRIC 4, Determining Whether an Arrangement Contains a Lease, based on terms and conditions existing at January 1, 2010.

v) Share based payments

IFRS 2 Share Based Payments has not been applied to equity instruments related to share based payment 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.

PERPETUAL ENERGY INC.
IFRS Reconciliation of Equity
As at January 1, 2010

		IFRS adjustments						
	Canadian GAAP	E&E	Financial Liabilities	ARO	Impairment	Share Based Payments	Other	IFRS
(Cdn$ thousands)	Note	(24a)	(24c)	(24d)	(24f)	(24g)	(24b,e)	
Assets								
Current assets								
Accounts receivable	$ 34,079	$ –	$ –	$ –	$ –	$ –	$ –	$ 34,079
Prepaid expenses and deposits	12,910							12,910
Marketable securities	163							163
Derivatives	46,152							46,152
	93,304	–	–	–	–	–	–	93,304
Derivatives	21,167							21,167
Property, plant and equipment	921,705	(111,604)		47,407			14,648	872,156
Exploration and evaluation	–	111,604						111,604
Goodwill	29,129				(23,129)			6,000
	972,001	–	–	47,407	(23,129)	–	14,648	1,010,927
Total assets	$ 1,065,305	$ –	$ –	$ 47,407	$ (23,129)	$ –	14,648	$ 1,104,231
Liabilities								
Current liabilities								
Accounts payable and accrued liabilities	$ 41,722	$ –	$ –	$ –	$ –	$ –	$ –	$ 41,722
Distributions payable	6,311							6,311
Share based payment liability	–					8,571		8,571
Bank debt	7,569							7,569
Convertible debentures	55,271							55,271
	110,873	–	–	–	–	8,571	–	119,444
Long-term bank debt	262,393							262,393
Convertible debentures	164,926							164,926
Derivative debenture liability	–		8,398					8,398
Gas over bitumen royalty obligation	77,167							77,167
Decommissioning obligations	194,588			58,756				253,344
Unitholders' liability	–		1,156,245					1,156,245
	699,074	–	1,164,643	58,756	–	–	–	1,922,473
Total liabilities	809,947	–	1,164,643	58,756	–	8,571	–	2,041,917
Unitholders' equity								
Unitholders' capital	1,156,245		(1,156,245)					–
Equity component of convertible debentures	10,844		(10,844)					–
Contributed surplus	19,470					(19,470)		–
Deficit	(932,680)		2,446	(11,349)	(23,129)	10,899	14,648	(939,165)
Total equity attributable to unitholders	253,879	–	(1,164,643)	(11,349)	(23,129)	(8,571)	14,648	(939,165)
Non-controlling interests	1,479							1,479
Total unitholders' equity	255,358	–	(1,164,643)	(11,349)	(23,129)	(8,571)	14,648	(937,686)
Total liabilities and unitholders' equity	$ 1,065,305	$ –	$ –	$ 47,407	$ (23,129)	$ –	$ 14,648	$ 1,104,231

PERPETUAL ENERGY INC.
IFRS Reconciliation of Equity
As at December 31, 2010

	Canadian GAAP	E&E	Financial Liabilities	ARO	Impairment	Share Based Payments	Other	IFRS
		IFRS adjustments						
(Cdn$ thousands)	Note	(24a)	(24c)	(24d)	(24f)	(24g)	(24b,e)	
Assets								
Current assets								
Accounts receivable	$ 35,459	$ –	$ –	$ –	$ –	$ –	$ –	$ 35,459
Prepaid expenses and deposits	5,028							5,028
Marketable securities	6,007							6,007
Derivatives	4,271							4,271
	50,765	–	–	–	–	–	–	50,765
Derivatives	3,562							3,562
Property, plant and equipment	954,750	(106,607)		23,770	(24,261)		11,813	859,465
Exploration and evaluation	–	107,474						107,474
Goodwill	29,129				(23,129)			6,000
	987,441	867	–	23,770	(47,390)	–	11,813	976,501
Total assets	$ 1,038,206	$ 867	$ –	$ 23,770	$ (47,390)	$ –	$ 11,813	$ 1,027,266
Liabilities								
Current liabilities								
Accounts payable and accrued liabilities	$ 73,979	$ –	$ –	$ –	$ –	$ –	$ –	$ 73,979
Dividends payable	4,449							4,449
Share based payment liability	803		(9,362)			10,689		2,130
	79,231	–	(9,362)	–	–	10,689	–	80,558
Long-term bank debt	182,612							182,612
Convertible debentures	219,689							219,689
Gas storage obligation	31,721							31,721
Gas over bitumen royalty obligation	70,497							70,497
Decommissioning obligations	199,191			36,972				236,163
Deferred tax liability	2,122							2,122
	705,832	–	–	36,972	–	–	–	742,804
Total liabilities	785,063	–	(9,362)	36,972	–	10,689	–	823,362
Equity								
Share capital	1,257,480		366			(384)		1,257,462
Equity component of convertible debentures	15,836		(1,848)					13,988
Contributed surplus	19,131		8,528			(17,791)		9,868
Deficit	(1,039,304)	867	2,316	(13,202)	(47,390)	7,486	11,813	(1,077,414)
Total equity	253,143	867	9,362	(13,202)	(47,390)	(10,689)	11,813	203,904
Total liabilities and equity	$ 1,038,206	$ 867	$ –	$ 23,770	$ (47,390)	$ –	$ 11,813	$ 1,027,266

PERPETUAL ENERGY INC.
IFRS Reconciliation of Total Comprehensive Loss
For the year ended December 31, 2010

		IFRS adjustments						
	Canadian GAAP	PP&E, E&E	Financial Liabilities	ARO	Borrowing costs	Impairment	Share based payments	IFRS
(Cdn$ thousands, except per share amounts)	Note	(24a,b)	(24c)	(24d)	(24e)	(24f)	(24g)	
Revenue								
Oil and natural gas	$ 260,217	$ –	$ –	$ –	$ –	$ –	$ –	$ 260,217
Royalties	(22,131)							(22,131)
Change in fair value of commodity price derivatives	93,661							93,661
Gas over bitumen	15,616							15,616
	347,363	–	–	–	–	–	–	347,363
Expenses								
Production and operating	91,161							91,161
Transportation	11,888							11,888
Exploration and evaluation	19,160	(867)						18,293
General and administrative	36,250						3,413	39,663
Gain on disposition of property, plant and equipment	(37,727)			(4,103)				(41,830)
Impairment losses	–					24,261		24,261
Depletion and depreciation	209,181	2,425		13,416				225,022
	329,913	1,558	–	9,313	–	24,261	3,413	368,458
Earnings (loss) from operating activities	17,450	(1,558)	–	(9,313)	–	(24,261)	(3,413)	(21,095)
Finance items								
Unrealized loss on derivative debenture liability	–		130					130
Unrealized gain on gas storage obligation derivative	(3,729)							(3,729)
Unrealized loss on marketable securities	1,257							1,257
Interest on Trust Units	–		40,549					40,549
Interest on convertible debentures	19,492							19,492
Interest on debt and gas storage obligation	12,460				(305)			12,155
Accretion on decommissioning obligations	14,394			(6,746)				7,648
	43,874	–	40,679	(6,746)	(305)	–	–	77,502
Loss before income tax	(26,424)	(1,558)	(40,679)	(2,567)	305	(24,261)	(3,413)	(98,597)
Deferred income taxes	2,122							2,122
Net loss and comprehensive loss	(28,546)	(1,558)	(40,679)	(2,567)	305	(24,261)	(3,413)	(100,719)
Net loss and comprehensive loss attributable to:								
Shareholders of the Corporation	(27,996)	(1,558)	(40,679)	(2,567)	305	(24,261)	(3,413)	(100,169)
Non-controlling interests	(550)	–	–	–	–	–	–	(550)
	$ (28,546)	$ (1,558)	$ (40,679)	$ (2,567)	$ 305	$ (24,261)	$ (3,413)	$ (100,719)
Loss per share								
Basic and diluted	$ (0.20)							$ (0.72)

Notes to the Reconciliations of Equity and Comprehensive income from Canadian GAAP to IFRS

a) IFRS 6 Adjustments – exploration for and evaluation of mineral resources

Under previous Canadian 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 resulted 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, the Corporation assessed the classification of activities designated as E&E which then determines the appropriate accounting treatment and classification of the costs incurred.

b) IFRS 16 Adjustments – 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 Canadian GAAP, adjusted only to segregate E&E assets, to adjust asset cost for revised decommissioning obligations and to record gains (losses) on dispositions under IFRS.

Under Canadian 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.

c) IAS 32 Adjustments – Financial instruments: presentation

The classification of certain equity items under Canadian GAAP was reviewed for conformity with the provisions of IAS 32. As a result, the Trust Units classified as equity under Canadian GAAP prior to conversion were reclassified to liabilities and recorded at amortized cost. The reclassification of Trust Units to Unitholders' liability also resulted in the reclassification of subscription receipts to liabilities and the conversion feature of convertible debentures to a derivative debenture liability. The derivative debenture liability is recorded at fair value on January 1, 2010 and the fair value is determined at each financial period end date until the conversion on June 30, 2010. The reclassification of the Trust Units to Unitholders' liability also resulted in distributions being recorded as interest on Trust Units during the six months ended June 30, 2010.

On June 30, 2010, the Trust completed its conversion and as a result the original carrying amount of the Unitholders' liability and derivative debenture liability were reclassified from liabilities to equity. In addition, the Corporation recorded adjustments to Unitholders' capital due to differences in the valuation of exercised options under IFRS compared to Canadian GAAP. These differences were charged to contributed surplus at June 30, 2010. Under IFRS the repayment of convertible debentures required the equity component on the convertible debenture to be allocated to deficit on January 1, 2010 whereas under Canadian GAAP it was allocated to contributed surplus.

d) IAS 37 Adjustments – Provisions

Decommissioning obligations (asset retirement obligations) had been measured under Canadian 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. The Corporation 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.

e) IAS 23 Adjustments – Borrowing costs

Under IAS 23, the Corporation has elected to commence capitalization borrowing costs as of August 1, 2009 on the Warwick gas storage facility. This increased the value of property, plant, and equipment and decreased interest expense in 2010.

f) IAS 36 Adjustments – Impairment

i) Goodwill

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 with no resulting impairment loss identified. The Corporation derecognized $23.1 million of goodwill previously recorded on an acquisition assigned to properties disposed prior to January 1, 2010.

ii) Property, plant and equipment

For the year ended December 31, 2010, the Corporation recognized an impairment of $24.3 million on the Birchwavy West, West Central and other South CGUs. The impairments recognized were based on the difference between the carrying value of the assets and the value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Under previous Canadian GAAP, the CGU's were included in the successful efforts ceiling test which and were not impaired at December 31, 2010.

g) IFRS 2 Adjustments – Share based payments

The application of IAS 32 caused the Corporation's share based payment plans in place on transition to be recorded as cash-settled share based payments up to the date of conversion. Under Canadian GAAP, the plans were considered to be equity-settled. As of January 1, 2010, both the Unit Incentive and Restricted Rights plan were fair-valued and recorded as liabilities. On January 1, 2010, the fair value amount was transferred from contributed surplus to the liability account and the remainder of contributed surplus was charged to deficit.

Upon conversion, the Share Option Plan was modified; the reduction in exercise price of the options was discontinued and replaced with a cash-settled Dividend Bonus Arrangement whereby upon exercise the employees receive cash for aggregate dividends accumulated subsequent to June 30, 2010 upon exercise and 25 percent of such dividends should the options expire unexercised. Under IFRS, the Dividend Bonus Arrangement is treated as a cash-settled share based payment arrangement measured at fair value, whereas under Canadian GAAP, this plan was classified as a liability but measured at intrinsic value.

h) Reclassifications

Certain amounts have been reclassified to conform with current presentation.

i) Adjustments to the Corporation's Cash Flow Statement under IFRS

Adjustments to borrowing costs under IAS 23 as noted in note 24(e) have the effect of increasing cash flows from operating activities and decreasing cash flow from investing activities by $0.3 million for the year ended December 31, 2010.

The remaining highlighted reconciling items above between Canadian GAAP and IFRS policies have no net impact on cash flows generated by the Corporation.

DIRECTORS

Clayton H. Riddell
Executive Chairman

Susan L. Riddell Rose
President, Chief Executive Officer and Director (4)

Karen A. Genoway
Independent Director (2) (3) (5)

Randall E. (Randy) Johnson
Independent Director (1) (3) (5)

Robert A. Maitland
Independent Director (1) (3) (5)

Geoffrey C. Merritt
Independent Director (1) (2) (4)

Donald J. Nelson
Independent Director (2) (4)

Howard R. Ward
Independent Director (3) (4) (5)

(1) Member of Audit Committee
(2) Member of Reserves Committee
(3) Member of Corporate Governance Committee
(4) Member of Environmental, Health & Safety Committee
(5) Member of Compensation Committee

OFFICERS

Susan L. Riddell Rose
President, Chief Executive Officer and Director

Cameron R. Sebastian
Vice President, Finance and Chief Financial Officer

Jeffrey R. Green
Vice President, Corporate and Engineering Services

Gary C. Jackson
Vice President, Land and Acquisitions

Marcello M. Rapini
Vice President, Marketing

R. William Thornton
Vice President, Enhanced Recovery and North Business Unit

Vicki L. Benoit
Vice President, Production Operations

Linda L. McKean
Vice President, South/West Business Unit

AUDITORS

KPMG LLP

BANKERS

Bank of Montreal

Canadian Imperial Bank of Commerce

The Bank of Nova Scotia

The Toronto-Dominion Bank

National Bank of Canada

ATB Financial

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

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STOCK EXCHANGE LISTING | TSX | PMT

CONVERTIBLE DEBENTURES | PMT.DB.C
PMT.DB.D
PMT.DB.E

ANNUAL MEETING

Shareholders are cordially invited to attend the Annual General Meeting to be held May 23, 2012 at 9:00 a.m. (MDT)

Calgary Petroleum Club
319 – 5 Avenue SW
Calgary, Alberta, Canada

Forward-Looking Information

Certain information regarding Perpetual in this report including management's assessment of future plans and operations may constitute forward-looking statements under applicable securities laws. The forward looking information includes, without limitation, statements regarding access to capital ; forecast production levels, production capability, funds flows, and timing thereof; operational plans including acquisition and disposition plans; current plans for the gas storage facility; forecast and realized commodity prices; forecast, funding and allocation of capital expenditures and timing thereof; anticipated operating cost sustainability; projected use of funds flow; planned drilling and development and the results thereof; expected levels of indebtedness under the credit facility and future borrowing base levels; the method of repaying Perpetual's outstanding convertible debentures; marketing and transportation plans; reserve estimates; and estimated funds flow sensitivity. Various assumptions were used in drawing the conclusions or making the forecasts and projections contained in the forward-looking information contained in this report, which assumptions are based on management analysis of historical trends, experience, current conditions, and expected future developments pertaining to Perpetual and the industry in which it operates as well as certain assumptions regarding the matters outlined above. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks, which could cause actual results to vary and in some instances to differ materially from those anticipated by Perpetual and described in the forward looking information contained in this report. Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described under "Risk Factors" in Perpetual Energy Inc.'s Annual Information Form and MD&A for the year ended December 31, 2011 and those included in reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR website (www.sedar.com and at Perpetual's website www.perpetualenergyinc.com). Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Perpetual's management at the time the information is reported and Perpetual disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities laws. For more information, please refer to "Forward-Looking Information" on page 49 of this report.

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