2013 RESULTS

PERPETUAL
ENERGY

PERPETUAL ENERGY INC. IS A CANADIAN ENERGY COMPANY FOCUSED ON LONG-TERM VALUE CREATION THROUGH OIL AND GAS BASED EXPLORATION, DEVELOPMENT, PRODUCTION AND MARKETING. PERPETUAL HAS BUILT A SPECTRUM OF RESOURCE-STYLE OPPORTUNITIES SPANNING HEAVY OIL, LIQUIDS-RICH NATURAL GAS AND BITUMEN. THESE BALANCE A BASE OF LEGACY SHALLOW GAS ASSETS. WITH A TRACK RECORD OF INNOVATION AND OPERATIONAL EXCELLENCE, PERPETUAL IS POSITIONED TO GROW AND PROSPER THROUGHOUT THE DYNAMIC CYCLES OF THE ENERGY BUSINESS.

2013 ANNUAL HIGHLIGHTS

2013 STRATEGIC PRIORITIES

Perpetual focused on five key strategic priorities in 2013:

1. Maximize value of Mannville heavy oil;
2. Position for growth of Edson liquids-rich gas;
3. Manage downside risk and reduce debt;
4. Advance and broaden the portfolio of high impact opportunities with risk-managed investment; and
5. Prepare to maximize value from shallow gas base assets in gas price recovery.

Significant progress was made with respect to these priorities during 2013, the results of which are highlighted below.

Maximize value of Mannville heavy oil

- Expenditures of $48.9 million were concentrated on the drilling and completion of 37 (35.7 net) horizontal heavy oil wells in the Mannville play.
- Heavy oil production increased 24 percent from 2012 to 3,178 bbl/d.
- Increased onsite processing and drying of oil have allowed access to enhanced oil marketing opportunities and improved pricing. Approximately 1,700 bbl/d are currently being shipped to market through rail arrangements further improving netbacks.
- Perpetual initiated a waterflood in a portion of the Mannville I2I pool for pressure maintenance to reduce the Sparky pool's decline rate and enhance recoverable oil reserves. Two wells were converted to injectors and water injection commenced late in the fourth quarter. Planning is underway to expand the waterflood in the pilot pool in the third quarter of 2014.

Position for growth of Edson liquids-rich gas

- West Central Alberta capital spending of $35.0 million was focused on the completion and tie-in of the fourth quarter 2012 drilling program at West Edson; drilling, completion and tie-in of five (2.5 net) new horizontal wells; as well as the build out of infrastructure and facilities to accommodate the next phase of production growth at West Edson.
- Greater Edson gas and natural gas liquids ("NGL" or "liquids") production grew 12 percent to 4,861 boe/d year-over-year.
- Perpetual and its partner continued to grow production capability with the expansion of the West Edson compressor station from 10 to 30 MMcf/d of gross capacity (50 percent net to Perpetual) in the first quarter of 2013.
- In early March 2013, Perpetual entered into rich gas premium agreements with Aux Sable Canada and an interconnection agreement with Alliance Canada to allow access to a premium market in the mid-west United States.
- To fulfill these arrangements, the West Edson compressor station was upgraded to produce sales quality gas through the installation of refrigeration and liquids handling equipment. At the same time, a 15.5 km sales pipeline and operated meter station was constructed to tie-in to the Alliance pipeline system. Start-up of the gas plant and sales pipeline commenced on October 1, 2013.
- The facility and pipeline projects, combined with the new marketing and transportation arrangements, are reducing operating costs, decreasing downtime and increasing overall netbacks for the West Edson production.
- Operating netbacks for the greater Edson area improved to $15.60/boe from $15.00/boe in 2012 due to reduced operating costs at West Edson with the start up of the refrigeration plant and sales facility on October 1, 2013. This will continue to improve in 2014 as the full year effect of these operating cost reductions is realized.
- With the plant modification, reported NGL production and reserves at West Edson have decreased in volume on a barrel per MMcf basis, but have increased in value with the new facility and sales configuration. A portion of the previously recovered liquids are now included in higher heat content gas sales and sold directly to Aux Sable while high grade condensate liquids (C5+) are recovered through the new plant.
- Perpetual increased its acreage position in the West Central district during the second quarter, primarily through undeveloped land acquisitions totaling $5.4 million.

Manage downside risk and reduce debt

- Perpetual closed four asset dispositions, including the sale of its non-producing Elmworth Montney assets in the first quarter, for net proceeds of $79.0 million. Additionally, the Company tendered its shares in Trioil to a cash offer for $1.9 million. Proceeds were used to strengthen Perpetual's balance sheet and to partially fund the 2013 capital program.
- To manage downside risk, Perpetual entered into a number of commodity price risk management contracts to mitigate the risk associated with natural gas prices and related basis differentials, oil prices and the West Texas Intermediate ("WTI") to Western Canadian Select differential ("WCS"), as well as foreign exchange rates. Realized hedging gains added $6.6 million to funds flow as a result of these strategies.
- To further diversify funds flow, in April 2013 Perpetual exercised its buyback option and increased its equity investment in the Warwick Gas Storage business ("WGS LP") from a 10 to a 30 percent interest for $19.1 million. Since April 2012, through new drilling and delta pressuring approvals, the working gas capacity of the storage facility has increased to 21.5 Bcf from 17 Bcf. Perpetual's net share of dividends from WGS LP contributed $2.4 million to funds flow in 2013.
- In April 2013, Perpetual's bank syndicate reduced the Corporation's borrowing base under its credit facility from $140 million to $110 million due to low natural gas pricing. This was renewed in October 2013 with effect until the next semi-annual borrowing base review in April 2014.
- Total net debt, including net bank debt ($67.2 million), convertible debentures and senior notes, was $377.0 million at year end 2013, a decrease of $10.8 million from year end 2012. The ratio of net debt to trailing 12 months funds flow at December 31, 2013 improved by 19 percent from year end 2012 to a ratio of 6.4 to 1.

Advance and broaden the portfolio of high impact opportunities with risk-managed investment

- A pilot project to develop bitumen in the Bluesky reservoir at Panny in northeast Alberta received funding approval through the Alberta government's Innovative Energy Technology Program ("IETP"). The cost for the Low-Pressure Electro-Thermally Assisted Drive ("LEAD") pilot project is estimated at $18 million. Funding through IETP is 30 percent of actual eligible costs to a maximum of $5.5 million. IETP funding was activated with the drilling of a water source well in the third quarter of 2013. Perpetual recovered $0.5 million from IETP in the fourth quarter related to preliminary drilling, completion and testing costs on the project in prior years.
- Potential development costs were fine-tuned and the minimum type curve requirement established for economic full scale development to recover the Company's captured Viking/Colorado shallow shale gas resource in eastern Alberta. A pilot project is designed and prepared for execution to assess various multi-stage fracture technologies to achieve the type curve and further prove up costs and expected economic returns to develop the extensive resource with horizontal wells.
- In West Central Alberta, Perpetual drilled one (0.5 net) exploratory horizontal well targeting the Fahler formation on recently acquired undeveloped land in the Alberta deep basin south of the Corporation's greater Edson core operating area. Tie in and extended flow test operations are underway to evaluate the potential of this zone for horizontal development.
- Perpetual entered into a farm out arrangement to fund the evaluation of prospective acreage for liquids-rich gas in the Duvernay formation at Waskahigan. The vertical stratigraphic test and follow-on horizontal well was spud in December, drilled to a total depth of 5,300 meters and rig released on February 14, 2014. Multi-stage fracture stimulation operations are expected to be completed after spring break-up.

Prepare to maximize value from shallow gas base assets in gas price recovery

- Lower operating costs for Perpetual's shallow gas assets resulted from optimization of facilities and gathering systems, field office consolidation and streamlining of metering and other operations. Operating costs related to shallow gas production decreased 13 percent from 2012 ($57.7 million) to $50.3 million.
- Production from shallow gas base assets was 63.7 MMcf/d, representing 72 percent of Perpetual's natural gas production. These assets have significant leverage to higher funds flow with improved natural gas prices.

2013 FINANCIAL AND OPERATING RESULTS SUMMARY

- Exploration and development spending of $96.7 million remained focused on two key plays: Mannville heavy oil and Edson liquids-rich gas. A total of 43 (38.7 net) wells were drilled; 37 (35.7 net) targeting heavy oil at Mannville and six (3.0 net) in the deep basin for liquids-rich gas. Additionally, $15 million of the capital expenditures related to facilities enhancements at West Edson.
- Oil and NGL production of 3,860 bbl/d was 12 percent higher than in 2012, reflecting Perpetual's focus on commodity diversification.
- Natural gas production of 88.9 MMcf/d was down 11 percent from 2012, as a result of asset dispositions and natural declines in Perpetual's shallow gas assets where limited capital was invested to add production. The decline was offset by a 24 percent gas production increase in West Central Alberta related to capital investment and strong performance in the greater Edson area. Compared to 2012, shallow gas production decreased 19 percent due to asset dispositions and natural declines, as capital investment and the operational focus were strategically shifted almost entirely to heavy oil and liquids-rich, resource-style gas assets.
- Heavy oil and deep basin production increased 17 percent from 2012 to 8,060 boe/d through successful execution of the asset base transformation strategy. Production from these assets represented 43 percent of total production and 36 percent of actual plus deemed production, up from 34 percent and 28 percent respectively in 2012.
- Gas and associated liquids production from the deep basin resource-style assets in West Central Alberta represented 26 percent of total production in 2013, up from 21 percent in 2012. High netback Mannville heavy oil production comprised 17 percent of total production.
- Total production decreased seven percent to 18,696 boe/d from 20,142 boe/d in 2012, due to the full year effect of non-core dispositions completed in 2012 combined with natural declines. These reductions were offset by 14 percent growth in gas and NGL production in the greater Edson area and 24 percent growth in Mannville heavy oil production, due to successful capital investment in these areas. Total actual and deemed production decreased nine percent to 22,479 boe/d from 24,592 boe/d in 2012 as a result of the above factors tied with the annual 10 percent reduction on deemed production.
- Production-related operating costs decreased five percent to $75.4 million as compared to $79.7 million in 2012, reflecting the impact of Perpetual's cost saving measures applied to the production of its shallow gas assets and the new operating cost structure at West Edson associated with the new plant. Cost savings were partially offset by higher operating costs associated with increased heavy oil production. On a boe basis, operating costs increased to $11.05/boe from $10.81/boe in 2012. This is a reflection of the high percentage of fixed costs associated with the Company's declining shallow gas assets, largely related to property taxes.
- Realized natural gas prices, including derivatives, increased six percent to $3.53/Mcf from $3.34/Mcf in 2012, reflecting hedging gains and the increase in AECO Index prices year-over-year.
- Oil and NGL prices, including derivatives, of $66.48/bbl increased four percent in 2013 despite a slight reduction in WCS pricing. Price improvements were realized through the delivery of higher grade heavy oil at sales points, as well as the sale of more condensate-rich NGL volumes in the fourth quarter related to the change in processing at West Edson.
- Royalty expense increased 50 percent to $19.0 million from $12.6 million in 2012. Annual Crown royalty adjustments of $2.6 million recorded in the second quarter of 2013, related to 2012 capital cost allowance, custom processing and operating costs adjustments, contributed materially to the increase in Crown royalties for 2013. In addition, certain Mannville heavy oil wells transitioned to higher royalty rates after reaching maximum volume recoveries under initial low royalty rate incentive periods. Increased Crown royalty rates associated with higher Alberta gas reference prices also contributed to the higher royalties.
- Operating netbacks improved 10 percent from 2012, to $15.23/boe, reflecting higher commodity prices and the increased percentage of higher priced oil and NGL in the production mix.
- Interest expense decreased 11 percent from $36.4 million during 2012 to $32.5 million, primarily due to the repayment of $74.9 million convertible debentures which matured in June 2012, with further decreases associated with lower bank debt as a result of property dispositions.
- Cash general and administrative ("G&A") expense decreased 10 percent to $24.5 million as compared to $27.1 million in 2012, primarily due to increased overhead recovery rates under new joint operating agreements combined with an increase in capital spending. Further reductions were attributable to reduced staffing levels and lower consulting fees.
- Funds flow of $58.5 million ($0.39 per share) increased 19 percent from $49.1 million ($0.33 per share) in 2012, as a result of stronger natural gas prices, increased production from superior netback oil and liquids-rich natural gas properties and higher dividends from WGS LP, combined with the reductions in operating costs, G&A and interest expense in 2013.
- The Corporation recorded net income of $7.6 million ($0.05 per share) as compared to a net loss of $76.0 million ($0.52 per share) in 2012.

RESERVES AND RESOURCE ESTIMATES

- Overall, the results of Perpetual's capital investment program in 2013 were extremely positive, with reserve additions as estimated by McDaniel and Associates Consultants Ltd. ("McDaniel") replacing production by close to 2.5 times.
- The majority of the reserve additions resulted from capital spending focused on Perpetual's two key diversifying strategies; liquids-rich natural gas in the Wilrich formation in the greater Edson area and heavy oil reserves in the Mannville area of eastern Alberta. Year-over-year reserves for these plays grew by 51 percent and now represent 59 percent of the Company's total proved and probable reserves, up from 32 percent at year end 2012, excluding the sold Elmworth property. On a commodity basis, oil and NGL represented 13 percent of total proved and probable reserves (13 percent of proved).
- With the continued successful execution of the Company's asset base transformation and commodity diversification strategies, the net present value of Perpetual's reserves, discounted at eight percent, increased by close to 25 percent from McDaniel's estimate at year end 2012, despite lower commodity price forecasts and the related negative economic reserve revisions, and the material asset disposition at Elmworth in March of 2013.
- Perpetual's exploration and development capital spending program resulted in the addition of 16.4 MMboe of proved and probable reserves in 2013. Reserve additions and net positive technical revisions due to performance replaced 2013 production of 6.8 MMboe by 240 percent.
- Total proved and probable reserves of 62.4 MMboe at December 31, 2013 were 17 percent lower than year end 2012 (75.0 MMboe), reflecting net dispositions of 13.1 MMboe, production of 6.8 MMboe and negative economic revisions due to lower forecast natural gas prices of 9.1 MMboe. Proved reserves also decreased six percent to 34.1 MMboe at year end 2013 from 36.3 MMboe at December 31, 2012.
- Future development capital ("FDC") estimated to bring proved and probable reserves to production decreased $151.8 million to $230.0 million year-over-year.
- Economic revisions due to lower commodity prices of 1.0 MMboe of proved reserves and 8.1 MMboe of probable undeveloped reserves were recorded at year end, consisting almost exclusively of shallow natural gas reserves in the Viking formation in eastern Alberta. These negative reserve revisions also included a reduction of $97.9 million to future development capital.
- Asset dispositions resulted in a reduction of 13.1 MMboe of proved and probable reserves (6.8 MMboe proved) along with a $122.8 million reduction in FDC, primarily in the Elmworth area.
- McDaniel's estimate of net present value (discounted at eight percent) of Perpetual's reserves at year end 2013 increased 24 percent ($131.1 million) from year end 2012 to $677 million. This increase in net present value was recorded despite lower commodity price assumptions and the overall reduction in reserves at year end 2013 resulting from asset dispositions, production and negative reserve revisions in the Viking formation.
- Realized finding and development costs of $9.29/boe reflect strong capital efficiencies in the Company's key focus areas of investment.
- Independent contingent resource assessment reports were prepared by McDaniel in 2011 and partially updated in the first quarter of 2013, resulting in the assignment of 1.36 billion barrels of discovered bitumen initially in place (best estimate) and 1.88 billion barrels of undiscovered bitumen initially in place (best estimate) on 27,113 acres of Perpetual's oil sands leases, primarily in the Panny Bluesky sandstone and Liege Grosmont and Leduc carbonate reservoirs.
- Best estimate bitumen contingent resource was estimated at 279 MMbbl at year end 2013 with 467 MMbbl of prospective resource also recognized.

Reserves Summary

Reserves categories (1)	Light and medium crude oil (Mbbl)	Heavy oil (Mbbl)	Natural gas (MMcf)	Natural gas liquids (Mbbl)	Oil equivalent (Mboe)
Proved producing	55	1,801	111,013	895	21,254
Proved non-producing	–	93	12,284	48	2,188
Proved undeveloped	–	537	54,217	1,071	10,644
Total proved	55	2,431	177,514	2,014	34,086
Probable producing	26	1,087	41,472	355	8,380
Probable non-producing (2)	–	102	25,384	48	4,381
Probable undeveloped	–	637	61,582	1,374	12,275
Probable shut-in gas over bitumen	–	–	19,871	–	3,312
Total probable	26	1,826	148,309	1,778	28,348
Total proved and probable	80	4,257	325,823	3,792	62,433

(1) Company interest reserves at December 31, 2013 as prepared by McDaniel using McDaniel forecast prices and costs; may not add due to rounding.

(2) Excludes Gas over Bitumen ("GOB") reserves.

Future Development Capital (1)

($ millions)	2014	2015	2016	2017	2018	Remainder	Total
Eastern Alberta shallow gas	1.0	4.8	5.6	0.3	0.5	1.3	13.5
Mannville heavy oil	16.4	6.1	-	-	-	-	22.5
Greater Edson Wilrich	39.7	40.6	50.4	51.8	10.6	-	192.9
Deep basin other	-	1.1	-	-	-	-	1.1
Total	57.1	52.6	56.0	52.1	11.1	1.3	230.0

(1) May not add due to rounding.

NET ASSET VALUE

- Perpetual's reserve-based net asset value ("NAV") (discounted at eight percent) at year end 2013 is estimated at $3.07 per share, up 67 percent from $1.84 per share calculated at year end 2012.

				Discounted at
($ millions, except as noted) (1)	Undiscounted	5%	8%	10%
Total proved and probable reserves (2)	$ 1,038	$ 780	$ 677	$ 622
Fair market value of undeveloped land (3)	180	180	180	180
Warwick Gas Storage (4)	28	28	28	28
Net bank debt (1) (5)	(67)	(67)	(67)	(67)
Convertible debentures	(160)	(160)	(160)	(160)
Senior notes	(150)	(150)	(150)	(150)
Additional future abandonment & reclamation costs (6)	(90)	(57)	(45)	(39)
Hedge book (7)	(9)	(9)	(9)	(9)
NAV	$ 770	$ 545	$ 454	$ 405
Shares outstanding (million) – basic	148	148	148	148
NAV per share ($/share)	$ 5.20	$ 3.68	$ 3.07	$ 2.74

(1) Financial information is per 2013 audited consolidated financial statements.

(2) Reserve values per McDaniel Report as at December 31, 2013, including Gas over Bitumen financial solution.

(3) Independent third party estimate.

(4) Reflects 30 percent interest in Warwick Gas Storage valued at proportionate acquisition value at April 29, 2013.

(5) Includes bank debt, net of working capital and Crown receivable.

(6) Amounts are in addition to amounts in the McDaniel report for future well abandonment costs, net of salvage value, related to developed reserves.

(7) Hedging adjustments as at December 31, 2013 relative to McDaniel price forecast.

2014 OUTLOOK

2014 STRATEGIC PRIORITIES

In 2014, Perpetual's top five strategic priorities include:

1. Reduce debt and manage downside risk;
2. Grow Edson liquids-rich gas production, reserves, cash flow, inventory and value;
3. Maximize value of Mannville heavy oil;
4. Maximize cash flow from shallow gas; and
5. Advance and broaden the portfolio of high impact opportunities with risk-managed investment.

The scope of activities that will drive results with respect to these priorities in 2014 are highlighted below.

Downside risk management

- Perpetual is planning capital spending in 2014 to be fully funded by funds flow.
- The Company is continuing to pursue dispositions in 2014, targeting proceeds of a minimum of $100 million, which will be utilized to strengthen the balance sheet.
- With recent strength in natural gas prices following the depletion of storage levels caused by cold winter weather throughout much of North America, Perpetual has entered into a number of forward sale transactions to help manage natural gas price risk and protect a base level of 2014 funds flow. In addition, multiple transactions related to managing downside risk associated with 2014 oil prices are also in place, including WTI fixed price and collar arrangements, WTI-WCS differential contracts and US/Cdn currency swaps. Perpetual will continue to actively manage these positions by monitoring changing market and business conditions.
- Application for regulatory approval for a second tranche of delta pressuring is expected to be submitted in the second quarter of 2014 to bring working gas capacity at Warwick Gas Storage to over 24 Bcf and increase annual diversified funds flow from WGS LP.

Edson Wilrich liquids-rich gas

- Perpetual expects to spend up to $44 million in West Central Alberta in 2014. The majority of the capital will be to drill, complete and tie-in up to 10 (5.5 net) wells in the greater Edson area to grow liquids-rich gas production. Additional facility enhancements are planned to add compression and other plant components to bring the capacity at West Edson to 60 MMcf/d plus associated C5+ liquids (50 percent working interest). With a continuous one-rig drilling program, new wells are expected to ramp up production to match the expanded facility capability.
- Activities to assess the optimal development spacing at West Edson are also planned in 2014, including monitoring production from a new tighter spacing infill well drilled in the first quarter and detailed core and high resolution log analysis. Perpetual expects these activities to increase understanding of both gas in place and variables influencing resource recovery, which may guide the recognition of additional reserves in the greater Edson area.

Mannville heavy oil

- A continuous one-rig winter drilling program will add 11 (9.7 net) heavy oil wells in the first quarter of 2014 for an estimated $13 million, with production from new wells ramping up late in the quarter. This program is primarily a continuation of downspacing in existing pools, with two exploratory wells targeting to further delineate future drilling inventory.
- Capital expenditures for the remainder of 2014 for Mannville heavy oil are estimated at $11 to $14 million, targeting up to 12 (8.3 net) wells to be drilled, completed and tied in after break up.
- A waterflood pilot in the Mannville I2I pool (67 percent working interest) was started up in December 2013. Reservoir modeling suggests positive impacts to decline rates in producing wells could be seen within six months. Additional infill drilling in the I2I pool is included in the 2014 drilling program in order to prepare to expand waterflood operations in the pool during the third quarter of 2014. Additional pools are prospective for secondary recovery through waterflood and regulatory applications and unitization work are proceeding. Reservoir modeling and lab tests are also underway to assess the economic viability of enhanced oil recovery through polymer flood.

Shallow gas

- Capital program activities are underway in Perpetual's legacy conventional shallow gas pools to maximize value and mitigate base production declines. Capital expenditures of $4 million are planned for the first quarter, primarily targeting high return facility optimization projects, well workovers and uphole recompletions in winter-only access areas in northeast Alberta.
- Up to an additional $5 million has been budgeted to optimize shallow gas properties for the remainder of 2014.

High impact opportunities

- Application for regulatory approval for the LEAD pilot has been submitted. Operations are largely restricted by winter access conditions, so material capital spending is not expected to commence until winter 2014/2015.
- Depending on the outlook for natural gas prices, capital activities could include a small pilot project evaluating drilling and completion techniques to define the technical and economic potential of the Colorado shallow shale gas resource in east central Alberta.
- Perpetual entered into a farm-out agreement on 6,240 acres of Duvernay rights in the Waskahigan area. In early December a horizontal Duvernay test well was spud which is currently awaiting completion. Once the earning terms have been fulfilled, Perpetual will retain a 35 percent working interest in 3,840 gross acres and 100 percent working interest in the rest of the land. Results of this well are expected early in the third quarter of 2014.

CAPITAL BUDGET

- Perpetual's Board of Directors has approved a $70 to $80 million capital budget for full calendar year 2014. The table below summarizes the capital plans in alignment with Perpetual's 2014 Strategic Priorities.

2014 Capital budget

($ millions, except as noted)	2014 Capital	Number of wells
West Central liquids-rich gas	$39 - $44	Up to 10 (5.5 net)
Mannville heavy oil	$24 - $27	Up to 23 (18.0 net)
Shallow gas	$7 - $9	–
Total	$70 - $80	Up to 33 (23.5 net)

FUNDS FLOW

- Based on the forward market for commodity prices on March 5, 2014, funds flow is estimated at $75 to $85 million, with oil and NGL production averaging 3,400 to 3,500 bbl/d and natural gas sales of approximately 90 to 95 MMcf/d. The following table reflects Perpetual's 2014 projected funds flow at various commodity price levels.

2014 Projected funds flow (1) ($ millions)					AECO Gas Price ($/GJ)
WTI oil price ($US/bbl)	3.50	4.00	4.50	5.00	5.50
75.00	71	75	78	82	86
85.00	72	75	79	83	86
95.00	75	79	82	86	90
105.00	75	79	83	86	90
115.00	70	73	77	81	84

(1) Giving effect to settled prices and commodity price risk management contracts in place at March 5, 2014 and the premium pricing received for higher heat content natural gas sales in West Centra Alberta.

FINANCIAL AND OPERATING HIGHLIGHTS

(Cdn$ thousands, except volume and per share amounts)	Three months ended December 31 2013	2012	% Change	Year ended December 31, 2013 2013	2012	% Change
Financial						
Oil and natural gas revenue	**49,075**	44,468	10	**201,294**	176,137	14
Funds flow [1]	**12,998**	11,158	16	**58,468**	49,087	19
Per share [1] [2]	**0.09**	0.08	13	**0.39**	0.33	18
Net earnings (loss)	**(13,745)**	(56,400)	(76)	**7,620**	(75,986)	110
Per share [2]	**(0.09)**	(0.38)	(76)	**0.05**	(0.52)	110
Total assets	**742,288**	729,888	2	**742,288**	729,888	2
Net bank debt outstanding [1]	**67,201**	77,827	(14)	**67,201**	77,827	(14)
Senior notes, at principal amount	**150,000**	150,000	–	**150,000**	150,000	–
Convertible debentures, at principal amount	**159,779**	159,972	–	**159,779**	159,972	–
Total net debt [1]	**376,980**	387,799	(3)	**376,980**	387,799	(3)
Capital expenditures						
Exploration and development [3]	**24,518**	21,185	16	**96,684**	79,724	21
Dispositions, net of acquisitions	**(483)**	(6,923)	(93)	**(70,840)**	(164,763)	(57)
Interest in Warwick Gas Storage	**–**	–	–	**19,129**	–	–
Other	**2**	23	(91)	**120**	271	(56)
Net capital expenditures	**24,037**	14,285	68	**45,093**	(84,768)	(153)
Common shares outstanding (thousands)						
End of period	**148,490**	147,455	1	**148,490**	147,455	1
Weighted average	**148,144**	147,085	1	**148,144**	147,085	1
Operating						
Average production						
Natural gas (MMcf/d) [4]	**90.3**	88.3	2	**88.9**	100.2	(11)
Oil and NGL (bbl/d) [4]	**3,509**	3,536	(1)	**3,860**	3,448	12
Total (boe/d) [5]	**18,559**	18,250	2	**18,696**	20,142	(7)
Gas over bitumen deemed production (MMcf/d) [5]	**19.5**	25.1	(22)	**22.7**	26.7	(15)
Average daily (actual and deemed – boe/d) [4] [5]	**21,809**	22,240	(2)	**22,479**	24,592	(9)
Average prices						
Natural gas, before derivatives ($/Mcf)	**3.37**	2.99	13	**3.26**	2.48	31
Natural gas, including derivatives ($/Mcf)	**3.62**	3.56	2	**3.53**	3.34	6
Oil and NGL, before derivatives ($/bbl)	**65.35**	62.02	5	**67.65**	64.26	5
Oil and NGL, including derivatives ($/bbl)	**65.88**	71.29	(8)	**66.48**	64.13	4
Barrel of oil equivalent, including derivatives ($/boe)	**30.09**	31.05	(3)	**30.56**	27.59	11
Drilling (wells drilled gross/net)						
Gas	**4/2.0**	3/1.5		**6/3.0**	8/5.5	
Oil	**5/5.0**	2/2.0		**37/35.7**	36/34.6	
Total	**9/7.0**	5/3.5		**43/38.7**	44/40.1	
Success rate (%)	**100/100**	100/100		**100/100**	100/100	

(1) These are non-GAAP measures. Please refer to "Non-GAAP Measures" below.

(2) Based on weighted average basic or diluted common shares outstanding for the period.

(3) Exploration and development costs include geological and geophysical expenditures.

(4) Production amounts are based on the Corporation's interest before royalty expense.

(5) The deemed production volume 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 volume is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen financial solution which is received monthly from the Alberta Crown as a reduction against other royalties payable.

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, 2013 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, 2013 and 2012. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are referred to the advisories for additional information 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 5, 2014.

NATURE OF BUSINESS: Perpetual is an oil and natural gas based energy company headquartered in Calgary, Alberta. Over the past five years, Perpetual has transitioned its business from a shallow gas focused cash flow distributing energy trust to build a diversified, growth-oriented, exploration, production and marketing company. Perpetual has a spectrum of opportunities in its resource-style portfolio of assets to support its growth strategy including liquids-rich natural gas ("liquids-rich") assets in the deep basin of West Central Alberta, heavy oil in eastern Alberta, oil sands leases in northern Alberta and an interest in a natural gas storage business which complement its legacy shallow gas production and resource base. Additional information on Perpetual, including the most recent filed Annual Information Form ("AIF"), can be accessed at www.sedar.com or from the Corporation's website at www.perpetualenergyinc.com.

ADVISORIES

NON-GAAP MEASURES: This document contains the following non-GAAP financial measures which do not have any standardized meaning prescribed by GAAP and are therefore unlikely to be comparable to similar measures presented by other issuers. Non-GAAP measures presented in this document should not be viewed as alternatives to measures of financial performance calculated in accordance with GAAP.

Operating netback: Perpetual considers operating netback a key performance measure as it demonstrates its profitability relative to current commodity prices. Operating netbacks are also calculated on a boe basis by deducting royalties, operating costs, and transportation from total revenue.

Funds flow: Management uses cash flow from operating activities before changes in non-cash working capital, changes in long term Crown receivable, settlement of decommissioning obligations and certain E&E costs described below ("funds flow"), funds flow per share and annualized funds flow to analyze operating performance and leverage. Funds flow is reconciled to its closest GAAP measure, cash flow from operating activities, as follows.

Funds flow GAAP reconciliation	Three months ended December 31		Year ended December 31	
($ thousands, except per share amounts)	**2013**	2012	**2013**	2012
Cash flow from operating activities	**12,353**	13,527	**52,333**	48,599
Exploration and evaluation costs (1)	**(19)**	(241)	**1,279**	100
Expenditures on decommissioning obligations	**859**	217	**2,497**	1,825
Changes in long term Crown receivable	**777**	(1,335)	**2,213**	(275)
Changes in non-cash operating working capital	**(972)**	(1,010)	**146**	(1,162)
Funds flow	**12,998**	11,158	**58,468**	49,087
Funds flow per share (2)	**0.09**	0.08	**0.39**	0.33

(1) The Corporation charges exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties and the cost of expired leases to income 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.

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

Realized revenue: Realized revenue includes oil and natural gas revenue, realized gains (losses) on economic hedges and 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.

Adjusted working capital surplus: Adjusted working capital surplus includes total current assets, current liabilities and long term Crown receivables excluding short-term derivative assets and liabilities related to the Corporation's economic hedging activities, assets and liabilities held for sale, share-based payment liabilities and current bank indebtedness.

Net debt and net bank debt: Net bank debt is measured as current and long term bank indebtedness including adjusted working capital surplus. Net debt includes the carrying value of net bank debt and the principle amount of senior notes and convertible debentures. Net bank debt and net debt are used by management to analyze leverage.

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 is not intended to represent the total funds from equity and debt received by the Corporation upon issuance.

VOLUME CONVERSIONS: 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 natural gas of 6 Mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indicator of value as the value ratio between natural gas and crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl.

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 future performance. All statements other than statements of historical fact may be forward-looking information and 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, natural gas liquids ("NGL") and oil; the existence, operations and strategy of the commodity price risk management program; the approximate amount of forward sales and economic hedges 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; 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 Corporation's asset base; the Corporation's acquisition and disposition strategy and the existence of acquisition and disposition 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 exploration and development; the corporate strategy; expectations regarding Perpetual's access to capital to fund its acquisition, exploration and development activities; the effect of future accounting pronouncements and their impact on the Corporation's financial results; expected realization of gas over bitumen ("GOB") royalty adjustments; future income tax and its effect on funds flow; 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, construction and waterflood 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 debt reduction initiatives; 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 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, unfavorable, 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.

SELECTED ANNUAL INFORMATION

($ thousands, except per share amounts)	**2013**	2012	2011
Financial			
Oil and natural gas revenue	**201,294**	176,137	246,256
Net income (loss) [(1)]	**7,620**	(75,986)	(95,893)
Per share [(1) (2)]	**0.05**	(0.52)	(0.65)
Funds flow	**58,468**	49,087	72,679
Per share [(2)]	**0.39**	0.33	0.49
Total assets [(1)]	**742,288**	729,888	1,025,750
Total long term liabilities [(1)]	**521,847**	594,342	728,180
Dividends to shareholders	**–**	–	28,865
Per share [(3)]	**–**	–	0.20
Net bank debt outstanding [(1)]	**67,201**	77,827	132,937
Senior notes, at principal amount	**150,000**	150,000	150,000
Convertible debentures, at principal amount	**159,779**	159,972	234,897
Total net debt [(1)]	**376,980**	387,799	517,834
Capital expenditures			
Exploration and development [(4)]	**96,684**	79,724	139,214
Dispositions, net of acquisitions	**(70,840)**	(164,763)	(33,953)
Interest in Warwick Gas Storage (“WGS LP”)	**19,129**	–	–
Other	**120**	271	11,795
Net capital expenditures	**45,093**	(84,768)	117,056
Shares outstanding (thousands)			
End of period	**148,490**	147,455	146,966
Weighted average	**148,144**	147,085	147,694
Operating			
Average production			
Natural gas (MMcf/d)	**88.9**	100.2	130.2
Oil and NGL (bbl/d)	**3,860**	3,448	1,976
Total (boe/d)	**18,696**	20,142	23,671
Gas over bitumen deemed production (MMcf/d)	**22.7**	26.7	26.4
Average production (actual and deemed – boe/d)	**22,479**	24,592	28,071
Average prices			
Natural gas – before derivatives ($/Mcf)	**3.26**	2.48	3.77
Natural gas – including derivatives ($/Mcf)	**3.53**	3.34	3.82
Oil and NGL – before derivatives ($/bbl)	**67.65**	64.26	73.67
Oil and NGL – including derivatives ($/bbl)	**66.48**	64.13	78.00
Wells drilled			
Natural gas – gross (net)	**6 (3.0)**	8 (5.5)	16 (15.5)
Crude oil – gross (net)	**37 (35.7)**	36 (34.6)	35 (34.0)
Other – gross (net)	**–**	–	11 (11.0)
Total – gross (net)	**43 (38.7)**	44 (40.1)	62 (60.5)

(1) Prior period amounts have been restated as a result of the GOB obligation being overstated and GOB revenue being understated. See note 2 of the Corporation’s annual audited consolidated financial statements.

(2) Based on weighted average shares outstanding for the year.

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

(4) Exploration and development costs include geological and geophysical expenditures.

OVERALL PERFORMANCE

Perpetual focused on five key strategic priorities in 2013:

- Maximize value of Mannville heavy oil;
- Position for growth of Edson liquids-rich gas;
- Manage downside risk and reduce debt;
- Advance and broaden the portfolio of high impact opportunities with risk-managed investment; and
- Prepare to maximize value from shallow gas base assets in gas price recovery.

Perpetual continued to focus its efforts on its asset transformation and commodity diversification strategy with capital spending directed towards Mannville heavy oil assets in eastern Alberta and liquids-rich assets in the Greater Edson area. During 2013, Perpetual drilled 37 (35.7 net) horizontal heavy oil wells in Mannville and 6 (3.0 net) deep basin wells. In addition, the West Edson gas processing facility was expanded to 37 MMcf/d (50 percent working interest) and enhanced with the construction of a refrigeration plant and sales pipeline with deliveries to the Alliance pipeline commencing in the fourth quarter of 2013.

As a result of Perpetual's commodity diversification strategy, daily oil and NGL production of 3,448 bbl/d in 2012 increased 12 percent to 3,860 bbl/d in 2013. Natural gas production declined 11 percent from 100.2 MMcf/d in 2012 to 88.9 MMcf/d in 2013 due to the impact of non-core natural gas asset dispositions in 2012 and natural declines with the concentration of capital spending focused on the development of heavy oil and liquids-rich assets.

Proceeds on dispositions, net of acquisitions, of $70.8 million in 2013 were primarily driven by $76.8 million in net proceeds received from the sale of Perpetual's Elmworth property during the first quarter of 2013. Perpetual spent approximately $8.1 million during 2013 on acquisitions primarily focused on undeveloped land in West Central to capture further exploration and development opportunities. Perpetual exercised its option to repurchase an additional 20 percent interest in WGS LP for $19.1 million in the second quarter of 2013 increasing its total interest from 10 to 30 percent.

The positive impact of Perpetual's capital activities in 2013 was reflected in the addition of 16.4 MMBoe of oil, natural gas and NGL reserves replacing production by close to 2.5 times. Total proved and probable reserves of 62.4 MMBoe were down 17 percent from 75.0 MMBoe in 2012 giving effect to reserve reductions of 6.8 MMBoe in production, 13.1 MMBoe in dispositions and 9.1 MMBoe in negative economic reserve revisions associated with undeveloped probable Viking formation reserves in eastern Alberta. Finding and development costs including changes in future development capital costs of $9.29 per boe reflect strong capital efficiencies in Perpetual's key focus areas of investment. With the highly profitable additions focused in the Corporation's key diversifying strategies, the net present value of Perpetual's reserves, discounted at eight percent, increased close to 25 percent from $545.9 million in 2012 to $677.0 million at year end 2013. A complete discussion of reserves is included in the Corporation's 2013 Annual Information Form ("AIF").

Funds flow increased 19 percent to $58.5 million in 2013 from $49.1 million in 2012 mainly due to increased revenues related to higher oil production and oil prices as well as higher gas prices year-over-year offsetting gas production declines. Lower operating costs also contributed to the increase in funds flow as did increased dividends from WGS LP as a result of strong performance in the gas storage business and the increase in Perpetual's share of the investment from 10 to 30 percent.

Increased funds flow and proceeds from dispositions more than offset Perpetual's 2013 capital spending which contributed to a reduction of $10.8 million in net debt from $387.8 million in 2012 to $377.0 million in 2013.

2013 FINANCIAL RESULTS

Capital expenditures

($ thousands)	**2013**	2012
Exploration and development	**95,405**	79,624
Geological and geophysical costs (1)	**1,279**	100
Interest in WGS LP	**19,129**	–
Acquisitions	**8,135**	2,407
Dispositions	**(78,975)**	(167,170)
Other	**120**	271
Total	**45,093**	(84,768)

(1) Geological and geophysical expenditures and dry hole costs are expensed directly in the Corporation's statement of income (loss); they are considered by Perpetual to be more closely related to investing activities than operating activities, and therefore are included with capital expenditures.

Exploration and development spending by area

($ thousands)	**2013**	2012
West Central liquids-rich gas	**42,360**	24,907
Mannville heavy oil	**49,316**	50,883
Shallow gas and other	**3,729**	3,834
Total	**95,405**	79,624

During 2013, exploration and development expenditures of $95.4 million continued to be focused on the Corporation's proven diversifying growth assets at Mannville for heavy oil and in West Central for liquids-rich gas.

Exploration and development spending in 2013 of $42.4 million related to the development of the Corporation's liquids-rich Wilrich play in the Edson area. Infrastructure spending included the expansion of the compressor station and the installation of a refrigeration plant at the West Edson gas processing facility as well as construction of a sales pipeline to tie-in to the Alliance Canada Pipeline system. The Corporation's development drilling program in West Central Alberta, which was designed to fill the new gas plant in West Edson, included five (2.5 net) liquids-rich gas wells. In addition, one (0.5 net) exploratory well was drilled in the Columbia area and has recently been placed on production to evaluate performance. Exploration and development spending at Mannville of $49.3 million included the completion of a 37 (35.7 net) horizontal heavy oil well drilling program during 2013.

Acquisitions of $8.1 million in 2013 related to undeveloped land acquisitions complementing Perpetual's' land position in West Central Alberta for liquids-rich gas.

Disposition proceeds of $79.0 million in 2013 were primarily related to the disposition of non-producing properties in Elmworth which closed in the first quarter of 2013 for net proceeds of $76.8 million. Dispositions completed during 2012 were the result of Perpetual's asset disposition program targeting $75 to $150 million in net proceeds which was achieved through dispositions of non-core natural gas and oil properties in the West Central and Eastern districts contributing $86.3 million in net proceeds with the remaining net proceeds of $80.9 million being attributable to the disposition of a 90 percent interest in WGS LP.

During the second quarter of 2013, Perpetual exercised its option to repurchase an additional 20 percent interest in WGS LP for $19.1 million increasing its interest from 10 percent to 30 percent.

Production

	2013	2012
Natural gas (MMcf/d)		
Eastern – North	**38.5**	50.1
Eastern – South	**25.2**	29.3
West Central	**25.2**	20.8
Total natural gas	**88.9**	100.2
Crude oil (bbl/d)		
Eastern – North	**7**	5
Eastern – South (1)	**3,150**	2,537
West Central	**48**	116
Total crude oil	**3,205**	2,658
NGL (bbl/d)		
Eastern – North	**–**	1
Eastern – South	**9**	6
West Central	**646**	783
Total NGL	**655**	790
Total actual production (boe/d)	**18,696**	20,142
Deemed natural gas production (MMcf/d)	**22.7**	26.7
Total actual plus deemed production (boe/d)	**22,479**	24,592

(1) Primarily Mannville heavy oil.

Total production of 18,696 boe/d for the year ended December 31, 2013 decreased seven percent from the prior year due to the full year effect of non-core asset dispositions completed in 2012.

Despite a 21 percent increase to Perpetual's West Central deep basin gas production, non-core asset dispositions in 2012 and natural declines in Perpetual's shallow gas assets led to an 11 percent reduction in average gas production to 88.9 MMcf/d from 100.2 MMcf/d recorded in 2012.

Oil production of 3,205 bbl/d increased 21 percent from 2,658 bbl/d in 2012 as a result of the successful drilling program targeting Mannville heavy oil.

NGL production in 2013 decreased by 17 percent from 790 bbl/d to 655 bbl/d as the higher liquids yield wells at Edson declined and spending for liquids-rich gas was focused at West Edson where liquids yields are lower than at Edson proper. In addition, the change in processing arrangements in West Edson, which started up operations in October 1, 2013, reduced the reported liquids recovery as a portion of the previously recovered liquids are now included in higher heat content gas sales while higher grade condensate liquids are now recovered through the new plant.

Deemed production for 2013 of 22.7 MMcf/d decreased 15 percent from 26.7 MMcf/d in 2012. The decrease reflects the annual 10 percent reduction assessed on deemed production volumes combined with wells reaching the end of their 10 year deemed production period. Wells are only eligible for deemed production and the associated GOB royalty adjustment for 10 years following shut-in.

Commodity prices

	2013	2012
Reference prices		
AECO Monthly Index ($/Mcf)	**3.16**	2.40
AECO Daily Index ($/Mcf)	**3.17**	2.39
Alberta Gas Reference Price ($/Mcf) (1)	**2.82**	2.25
West Texas Intermediate ("WTI") light oil ($US/bbl)	**97.97**	94.20
Western Canadian Select ("WCS") differential ($US/bbl)	**(25.20)**	(21.03)
Average Perpetual prices		
Natural gas		
Before derivatives ($/Mcf) (2)	**3.26**	2.48
Percent of AECO Monthly Index	**103**	103
Including derivatives ($/Mcf)	**3.53**	3.34
Percent of AECO Monthly Index	**112**	139
Oil and NGL		
Before derivatives ($/bbl)	**67.65**	64.26
Including derivatives ($/bbl)	**66.48**	64.13
Barrel of oil equivalent		
Average realized price ($/boe)	**30.56**	27.59

(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.

AECO Monthly Index prices of $3.16/Mcf for the year ended December 31, 2013 increased 32 percent from $2.40/Mcf for the same period in 2012. Colder than normal weather in late February and March of 2013 helped reduce the surplus in U.S. natural gas storage facilities by over 800 Bcf at March 31, 2013 versus March 31, 2012, which contributed to price appreciation through to the end of the second quarter of 2013. Following this increase, NYMEX prices declined due to reduced cooling demand resulting from mild summer weather and gas to coal switching by power producers. New TransCanada mainline pipeline tariffs, effective July 1, 2013 changed the pricing for short term pipeline rates which stranded gas in Alberta and forced storage levels in the province to peak capacity. This in turn caused AECO basis markets to widen, and third quarter AECO Monthly Index prices to decrease. AECO basis narrowed again in the fourth quarter of 2013 with normal seasonal heating demand helping to restore natural gas prices.

Increased AECO index prices were reflected in Perpetual's natural gas price before derivatives with an increase of 31 percent from $2.48/Mcf in 2012 to $3.26/Mcf in 2013.

Perpetual's average realized gas price, including derivatives, increased six percent in 2013 to $3.53/Mcf from $3.34/Mcf in 2012. The Corporation's realized 2012 natural gas price was significantly enhanced by realized gains on natural gas derivatives with close to 75 percent of Perpetual's production being economically hedged above settled market prices during that period. In response to the new pipeline tariffs at the beginning of the third quarter of 2013, Perpetual managed its downside risk by increasing gas hedges. Realized gains of $8.3 million on financial natural gas contracts led to an average 2013 gas price that was 112 percent of the AECO Monthly Index.

Perpetual's oil and NGL price, before derivatives, of $67.65/bbl increased five percent in 2013 compared to 2012. Slightly increased WTI prices were offset by a widening of WTI to the WCS differential price. However, price improvements were realized through the delivery of higher grade oil at the sales points related to drying operations implemented at the majority of the Mannville heavy oil production pads offsetting the reduced Canadian benchmark prices.

Perpetual's realized oil and NGL prices, including derivatives, were impacted by losses recorded on financial WTI fixed price contracts resulting in realized oil and NGL prices that were lower than prices before derivatives for the year ended December 31, 2013. Losses of $2.6 million on financial WTI contracts were partially mitigated by $0.9 million in call option premiums received during the first quarter of 2013.

Risk management

Perpetual's risk management strategy is focused on using both physical and financial derivatives to provide increased certainty in funds flow by mitigating the effect of commodity price volatility, to lock in economics on capital programs and acquisitions, and to take advantage of perceived anomalies in commodity markets. Perpetual also utilizes foreign exchange swaps and physical or financial swaps related to the differential between natural gas prices at the AECO and NYMEX trading hubs and oil basis differentials between WTI and WCS in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Corporation's realized commodity prices.

Natural Gas

Perpetual has in place natural gas hedges on 42 percent of estimated natural gas production and deemed natural gas production for the remainder of 2014. The following tables provide a summary of derivative natural gas contracts in place as at March 5, 2014:

Fixed price natural gas forward sales arrangements (net of related financial fixed-price natural gas purchase contracts) at the AECO trading hub:

Type of contract	Term (1)	Volumes at AECO (GJ/d)	Price ($/GJ) (2)	Futures market ($/GJ) (3)
Financial	April – June 2014	20,825	4.01	4.36
Financial	April – October 2014	26,100	4.02	4.35
Physical	April – October 2014	5,275	4.06	4.35
Financial	April – December 2014	10,000	3.71	4.39
Financial	July – December 2014	22,500	4.25	4.41

(1) Excludes settled and prompt month contracts.

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

(3) Futures market prices are based on closed forward AECO prices as of March 5, 2014.

Sold natural gas call option:

Type of contract	Term	Expiry date	Volumes at AECO (GJ/d)	Strike price ($/GJ)	Futures market ($/GJ) (1)
Call	April – December 2014	Monthly 2014	10,000	4.25	4.39

(1) Futures market prices are based on closed forward AECO prices as of March 5, 2014.

Financial forward gas sales arrangements to fix the basis differentials between NYMEX and AECO trading hubs:

Type of contract	Term (1)	Volumes at NYMEX-AECO (MMBtu/d)	Price ($/MMBtu) (2)	Futures market ($/MMBtu) (3)
Financial	April – October 2014	7,500	(0.48)	(0.37)

(1) Excludes settled and prompt month contracts.

(2) Average price is in $US and calculated using weighted average price for net open contracts; the price at which these contracts settle is equal to the NYMEX index less a fixed basis amount.

(3) Futures market prices are based on closed forward NYMEX-AECO differential prices as of March 5, 2014.

Crude Oil

Perpetual has crude oil financial contracts in place for 1,750 bbl/day of crude oil production for the remainder of 2014 with non-triggered WTI call options of 2,000 bbl/day for 2014 and 1,500 bbl/day for 2015. The following tables provide a summary of derivative crude oil contracts in place as at March 5, 2014:

Fixed price oil sales arrangements in $US

Type of contract	Term (1)	Volumes at WTI (bbl/d)	Price ($/GJ) (2)	Futures market ($/GJ) (3)
Financial	March – June 2014	750	90.00	99.70
Financial	March – December 2014	250	90.00	96.90

(1) Excludes settled contracts.

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

(3) Futures market prices are based on forward WTI oil prices as of March 5, 2014.

Costless collar oil sales arrangements in $US:

Type of contract	Term (1)	Volumes at WTI (bbl/d)	Floor price ($US/bbl) (2)	Ceiling price ($US/bbl) (2)	Futures market ($US/bbl) (3)
Collar	March – December 2014	500	85.00	91.10	96.90
Collar	March – December 2014	500	85.00	91.20	96.90
Collar (4)	March – December 2014	500	90.00	103.15	96.90

(1) Excludes settled contracts.

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

(3) Futures market prices are based on forward WTI oil prices as of March 5, 2014.

(4) In this collar arrangement Perpetual received a ceiling price above the market price for such collars, and in exchange should the WTI index settle above $US 103.15/bbl in any month during the contract period Perpetual will receive a price of $US 93.00/bbl.

Costless collar oil sales arrangements in Cdn$:

Type of contract	Term (1)	Volumes (bbl/d)	Floor price (Cdn$/bbl)	Ceiling price (Cdn$/bbl)	Futures market (Cdn$/bbl) (2)
Collar	January – December 2015	500	87.50	95.25	88.30
Collar	January – December 2015	500	87.50	95.75	88.30

(1) Excludes settled contracts.

(2) Futures market prices are based on forward WTI oil prices as of March 5, 2014.

Basis differential contracts between WTI and WCS trading:

Type of contract	Term (1)	Volumes (bbl/d)	WTI-WCS differential ($US/bbl) (2)	Futures market ($US/bbl) (3)
Financial	April – December 2014	2,000	(21.64)	(21.90)

(1) Excludes settled and prompt month contracts.

(2) Average price calculated using weighted average price for net open contracts; the price at which these contracts settle is equal to the WTI index less a fixed basis amount.

(3) Futures market prices are based on forward WTI-WCS differential prices as of March 5, 2014.

Sold oil call options:

Type of contract	Term	Expiry date	Volumes at WTI (bbl/d)	Strike price ($US/bbl WTI)	Futures market ($US/bbl WTI) (1)
Call	March – December 2014	Monthly 2014	2,000	105.00	96.90
Call	January – December 2015	Monthly 2015	1,500	100.00	88.30

(1) Futures market prices are based on forward WTI oil prices as of March 5, 2014.

Foreign Exchange

U.S. dollar forward sales arrangements:

Type of contract	Notional $US/month	Exchange rate (Cdn$/$US)	Term (1)
Financial	1,000,000	1.1000	March 2014 – June 2015

(1) Excludes settled contracts.

The Corporation receives $1,000 each day during the month that the daily exchange rate is between $1.0000 and $1.1000. If the average monthly exchange rate is greater than $1.1000 the Corporation pays $US 1,000,000 multiplied by the difference between the average monthly exchange rate and $1.1000. No settlement occurs between the Corporation and the counterparty if the average monthly exchange rate settles below $1.0000.

Type of contract	Notional floor $US/month	Notional ceiling $US/month	Exchange rate floor (Cdn$/$US)	Exchange rate ceiling (Cdn$/$US)	Term
Financial	2,500,000	5,000,000	1.0400	1.1410	July 2014 – December 2015

If the average monthly exchange rate is greater than the exchange rate ceiling, the Corporation pays $US 5,000,000 multiplied by the difference between the average monthly exchange rate and $1.1000. If the monthly average exchange rate settles below the exchange rate floor, the Corporation receives $US 2,500,000 multiplied by the difference between the average monthly exchange rate and the exchange rate floor.

Type of contract	Notional amount $US/month	Notional ceiling $US/month	Exchange rate floor (Cdn$/$US)	Exchange rate ceiling (Cdn$/$US)	Term
Financial	1,000,000	2,000,000	1.1000	1.1225	March – June 2014
Financial	1,000,000	2,000,000	1.1000	1.1305	March – June 2014

(1) Excludes settled contracts.

If the average monthly exchange rate is less than the exchange rate floor, the Corporation receives $US1,000,000 multiplied by the difference between the average monthly exchange rate and the exchange rate floor. If the monthly average exchange rate is between the exchange rate ceiling and exchange rate floor, the Corporation receives $US1,000,000 multiplied by the difference between the average monthly exchange rate and the exchange rate ceiling. If the average monthly exchange rate is greater than the exchange rate ceiling, the Corporation pays $US2,000,000 multiplied by the difference between the average monthly exchange rate and the exchange rate ceiling.

Revenue

($ thousands, except as noted)	**2013**	2012
Petroleum and natural gas ("P&NG") revenue		
Natural gas (1)	**105,965**	90,788
Oil and NGL (1)	**95,329**	81,090
Total P&NG revenue	**201,294**	171,878
Other revenue		
Gas storage revenue	**–**	4,259
Unrealized gains (losses) on derivatives	**1,783**	(2,224)
Realized gains on derivatives	**6,275**	29,035
Total other revenue	**8,058**	31,070
Total revenue	**209,352**	202,948
Per boe	**30.68**	27.53

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

Perpetual's P&NG revenue, before derivatives, for the year ended December 31, 2013 of $201.3 million increased 17 percent from 2012 due to higher oil and NGL production, a larger proportion of production from oil and NGL, and improved oil and natural gas prices in 2013. Natural gas revenue, before derivatives, of $106.0 million in 2013 increased 17 percent from $90.8 million in 2012 with increased natural gas prices more than offsetting the reduction in natural gas production associated with 2012 property dispositions. Oil and NGL revenues of $95.3 million were $14.2 million higher than the prior year with higher realized prices and increased production as a result of Perpetual's focus on commodity diversification with 2012 and 2013 capital spending programs directed almost exclusively to the development of oil and liquids-rich gas assets.

Realized gains on derivatives in 2013 totaled $6.3 million compared to $29.0 million for the same period in 2012. Gains in 2013 were primarily due to gains on natural gas and foreign exchange contracts which were partially offset by losses on oil contacts. In addition, Perpetual received $0.9 million in 2013 and $2.5 million in 2012 related to call options premiums. In 2012, Perpetual had entered into economic hedging contracts which represented close to 75 percent of actual and deemed natural gas production in order to protect funds flow in anticipation of a very low gas price environment.

The Corporation recorded unrealized gains on derivatives of $1.8 million during 2013 and losses of $2.2 million in 2012, representing the change in mark-to-market value of derivative contracts as forward commodity prices change. Unrealized gains and losses on derivatives are excluded from the Corporation's calculation of funds flow as they are non-cash. Derivative gains and losses vary depending on the nature and extent of economic hedging contracts in place, which in turn, varies with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

Royalties

($ thousands, except as noted)	**2013**	2012
Crown	**9,924**	5,562
Freehold and overriding	**9,118**	7,103
Total	**19,042**	12,665
Crown (% of total P&NG sales)	**4.9%**	3.2%
Freehold and overriding (% of total P&NG sales)	**4.5%**	4.1%
Total (% of P&NG sales)	**9.4%**	7.3%
Per boe	**2.79**	1.72

The 2013 combined average royalty rate on P&NG revenues increased to 9.4 percent from 7.3 percent in 2012 as a result of increased Crown royalty rates associated with higher Alberta gas reference prices. In addition, certain of the Corporation's Mannville heavy oil wells transitioned to higher royalty rates after reaching maximum volume recoveries under initial low royalty rate incentive periods. Annual Crown royalty adjustments of $2.6 million recorded in the second quarter of 2013 further contributed to the increase in Crown royalty rates for 2013. These adjustments related to 2012 capital cost allowance, custom processing and operating costs. The Crown adjusts these deductions from a corporate level to a facility level annually in June of each year.

Freehold and overriding royalties averaged 4.5 percent of total P&NG revenue in 2013, compared to 4.1 percent in 2012 as a result of increased oil production on freehold lands in the Mannville area which carry a higher freehold royalty rate than the Corporation's production on Crown lands.

Production and operating expenses

($ thousands, except as noted)	**2013**	2012
P&NG production expense	**75,414**	79,709
Gas storage operating expense (1)	**–**	2,031
Total	**75,414**	81,740
Per boe	**11.05**	11.09

(1) No longer accounted for on a consolidated basis after April 25, 2012.

P&NG production expense of $75.4 million in 2013 decreased five percent from $79.7 million in 2012, reflecting the impact of Perpetual's cost saving measures applied to the production of its shallow gas assets and the new operating cost structure at West Edson associated with the new plant which started up on October 1, 2013. Cost savings were partially offset by higher operating costs associated with increased heavy oil production. On a boe basis, operating costs increased from $10.81/boe in 2012 to $11.05/boe in 2013. The increase in cost per boe was the result of the growth in heavy oil production combined with high fixed costs, primarily property tax, associated with the Corporation's declining shallow gas assets.

Total production and operating expenses decreased eight percent from $81.7 million in 2012 to $75.4 million in 2013 as no operating expenses were recorded for the gas storage business in 2013 with the change in accounting treatment. The overall reduction of the Corporation's interest beginning April 2012 resulted in the investment being accounted for using the equity method rather than line-by-line consolidation.

Transportation costs

($ thousands, except as noted)	**2013**	2012
Transportation costs	**10,163**	8,773
Per boe	**1.49**	1.19

Transportation costs include clean oil trucking and transportation as well as costs to transport natural gas from the plant gate to a commercial sales point. Transportation costs in 2013 increased to $10.2 million from $8.8 million for the same period in 2012 primarily due to increased oil production volumes combined with a change in operating procedure related to Perpetual increasing its onsite processing of oil to meet sales point specifications. This resulted in a change in classification from operating costs (emulsion trucking) to transportation costs (clean oil trucking). This change to onsite processing has enhanced oil marketing opportunities and improved the overall netback for heavy oil production from the Mannville area.

Operating netbacks

($ thousands, except as noted)	**2013**	2012
Operating netback		
Realized revenue (1) (2)	**208,522**	203,359
Royalties	**(19,042)**	(12,665)
Operating costs (1)	**(75,414)**	(79,709)
Transportation	**(10,163)**	(8,773)
Total operating netback	**103,903**	102,212
Boe operating netback ($/boe)		
Realized revenue (1) (2)	**30.56**	27.58
Royalties	**(2.79)**	(1.72)
Operating costs (1)	**(11.05)**	(10.81)
Transportation	**(1.49)**	(1.19)
Boe operating netback	**15.23**	13.86

(1) Prior period excludes amounts related to the operation of the gas storage business as revenue and expenses were no longer accounted for on a consolidated basis after April 25, 2012.

(2) See "Non-GAAP measures" in this MD&A.

Perpetual's operating netback of $15.23/boe ($103.9 million) in 2013 increased 10 percent from $13.86/boe ($102.2 million) in 2012, primarily reflecting the increased percentage of higher netback production from crude oil, as well as natural gas and NGL in the Greater Edson area. Increased oil production as a percentage of the production mix, higher realized oil prices and lower operating expenses were partially offset by increased royalties and transportation expenses.

Gas over bitumen revenue ("GOB")

($ thousands, except as noted)	**2013**	2012
GOB revenue (1)	**8,905**	6,768
Per boe	**1.30**	0.92

(1) Prior period amounts have been restated as a result of the GOB obligation being overstated and GOB revenue being understated. See note 2 of the Corporation's annual audited consolidated financial statements.

Perpetual receives GOB royalty adjustments from Alberta Energy as compensation for its ownership in wells that have been shut-in or denied the right to produce as a result of bitumen conservation decisions. The monthly royalty adjustments are based on the Corporation's net deemed production, which is calculated on a well by well basis and declines by 10 percent per year over a 10 year period. GOB royalty adjustments are recognized as revenue.

Perpetual recorded $8.9 million in GOB revenue in 2013 compared to $6.8 million in 2012. The increase was primarily as a result of higher Alberta reference prices which more than offset the annual 10 percent deemed production decline.

Collection of GOB royalty adjustments was limited by the Alberta government to deductions from the Corporation's monthly natural gas royalty invoices. Beginning in 2014, royalty adjustments are now collected on behalf of Perpetual by one of its partners in the GOB wells with Perpetual's share being received in cash on a monthly basis. As of December 31, 2013, the Corporation had accumulated $18.1 million (December 31, 2012 – $17.7 million) of GOB adjustments receivable from the Crown of which $11.0 million (December 31, 2012 – $8.8 million) has been classified as long term. Perpetual will recover this receivable by applying future gas Crown royalties against the accumulated receivable.

Perpetual has recorded a GOB provision at December 31, 2013 of $2.9 million (December 31, 2012 - $2.7 million), which is adjusted to its fair value each reporting period. The provision represents estimated royalty adjustments that are repayable to the Crown in the future as an overriding royalty on gas production from wells which resume production within the GOB area.

GOB restatement

During preparation of the consolidated financial statements for the year ended December 31, 2013, Perpetual determined that the GOB obligation as at December 31, 2012 and January 1, 2012 was overstated based on the present value of expected repayments of royalty adjustments received.

Previously, Perpetual recognized the undiscounted amount of all royalty adjustments received as gas over bitumen obligation. No GOB revenue was recognized for the royalty adjustments received unless it related to shut-in wells that had been sold, where entitlement to the royalty adjustments were retained but the obligation for repayment had been transferred to the purchaser. By recording the GOB obligation at the undiscounted amount of royalty adjustments received for retained shut-in wells, Perpetual understated GOB revenue in prior periods and the GOB obligation was overstated.

The effect of the restatement on the consolidated statement of financial position as at January 1 and December 31, 2012 is as follows:

			January 1, 2012			December 31, 2012
	As reported	Adjustments	Restated	As reported	Adjustments	Restated
Long-term Crown receivable (1)	–	9,059	9,059	–	8,784	8,784
GOB obligation	74,705	(71,349)	3,356	44,553	(41,816)	2,737
Deficit (2)	(1,206,506)	80,408	(1,126,098)	(1,252,684)	50,600	(1,202,084)

(1) Long-term Crown receivable consists primarily of gas Crown royalty adjustments expected to be received by way of reduced gas Crown royalties beyond one year from the reporting date.

(2) Opening deficit reflects the accumulated impact of understated gas over bitumen revenue for prior periods.

For the year ended December 31, 2012, Perpetual previously recognized $37.2 million as GOB revenue which included a $33.1 million reduction to the GOB obligation related to sold wells. Upon restatement, this amount is included as an adjustment to the opening deficit on January 1, 2012.

The effect of the restatement on the consolidated statement of income (loss) and comprehensive income (loss) for the year ended December 31, 2012 is as follows:

			Year ended December 31, 2012
($ thousands)	As reported	Adjustments	Restated
GOB revenue	37,195	(30,427)	6,768
Finance expense	(34,579)	619	(33,960)
Net loss	(46,178)	(29,808)	(75,986)
Net loss per share – basic and diluted	(0.31)	(0.21)	(0.52)

The effect of the change in accounting is immaterial to the interim financial statements for all quarters in 2012 or 2013 except for the third quarter of 2012. For the third quarter of 2012, GOB revenue was overstated by $28.0 million and net loss was understated by $28.0 million ($0.18 per share – basic and diluted).

Exploration and evaluation

($ thousands)	**2013**	2012
Lease rentals	**3,269**	3,424
Geological and geophysical costs (1)	**1,279**	100
Lease expiries	**2,715**	5,758
Total exploration and evaluation	**7,263**	9,282

(1) Geological and geophysical expenditures and dry hole costs are expensed directly in the Corporation's statement of income (loss) as they are considered by Perpetual to be more closely related to investing activities than operating activities, and therefore are included with capital expenditures.

Exploration and evaluation ("E&E") costs include lease rentals on undeveloped acreage, geological and geophysical costs and lease expiries. E&E costs of $7.3 million in 2013 were $2.0 million lower than the prior year as a result of fewer lease expiries, partially offset by additional seismic purchases.

General and administrative ("G&A") expenses

($ thousands, except as noted)	**2013**	2012
Cash G&A expense	**24,509**	27,124
Compensation expense (non-cash)	**3,974**	4,349
Total G&A Expense	**28,483**	31,473
Cash G&A expense – per boe	**3.59**	3.68
Compensation expense (non-cash) ($/boe)	**0.58**	0.59

G&A expenses decreased 10 percent from $31.5 million in 2012 to $28.5 million in 2013. Cash G&A expense decreased from $27.1 million in 2012 to $24.5 million in 2013 due to increased overhead recovery rates under new joint operating agreements combined with an increase in capital spending. Further reductions were attributable to reduced staffing levels and lower consulting fees. Decreased compensation expense was related to a reduction in share based awards granted in 2013 compared to 2012 attributable to reduced staffing levels.

Gains on dispositions

Property dispositions during 2013 generated net cash proceeds of $79.0 million, resulting in gains on dispositions of $52.1 million primarily related to the Elmworth property disposition completed in the first quarter of 2013. The Elmworth property had no production or funds flow from operations and therefore the disposition did not have a negative effect on Perpetual's 2013 production or funds flow. Proceeds from dispositions were applied to reduce outstanding bank debt as well as to fund capital expenditures in excess of funds flow, including the purchase of an additional 20 percent interest in WGS LP.

Impairment

At December 31, 2013, indicators of potential impairment reversals were identified resulting in reversal of a previous years' impairment charge of $5.2 million on assets geographically located within the West Central Cash Generating Unit ("CGU"). Impairments were reversed primarily due to positive reserve revisions related to the strong performance of Perpetual's wells in West Edson.

At December 31, 2012, 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 $54.3 million was recorded for 2012 as a result of this analysis. The impairment was recorded within the Birchwavy East, Birchwavy West and Other South CGUs. The impairment was primarily due to lower natural gas prices causing negative reserve revisions on the Corporation's primarily undeveloped Viking reserves located within the Birchwavy East and Birchwavy West CGUs.

Depletion and depreciation ("D&D")

($ thousands, except as noted)	**2013**	2012
Depletion and depreciation	**92,877**	105,667
Per boe	**13.61**	14.33

Perpetual recorded $92.9 million of depletion and depreciation expense in 2013. On a boe basis, 2013 D&D expense of $13.61/boe decreased five percent from $14.33/boe in 2012. This reduction reflects a lower depletable cost base due to impairment losses recorded at December 31, 2012 driven by natural gas reserve reductions and associated future development costs as well as an overall decrease in production.

Finance expenses

Interest

($ thousands)	**2013**	2012
Interest	**28,932**	32,483
Amortization of debt issue costs	**3,550**	3,871
Interest	**32,482**	36,354

Interest expense decreased 11 percent from $36.4 million during 2012 to $32.5 million during 2013, primarily due to the repayment of $74.9 million convertible debentures which matured in June 2012 with further decreases associated with lower bank debt as a result of property dispositions. Interest expense for 2013 included interest on the Corporation's senior notes of $13.7 million (2012 - $13.7 million), interest on convertible debentures of $14.4 million (2012 - $17.2 million) and interest on bank debt of $4.4 million (2012 - $5.5 million).

Other finance expenses

($ thousands)	**2013**	2012
Accretion on decommissioning obligations	**4,439**	4,813
Change in estimate on GOB provision (1)	**211**	(619)
Loss (gain) on marketable securities	**92**	(801)
Loss (gain) on call option	**1,274**	(47)
Gain on retained investment in former subsidiary	**–**	(2,104)
Gain on gas storage obligation derivative	**–**	(3,636)
Other finance expenses	**6,016**	(2,394)

(1) Prior period amounts have been restated as a result of the GOB obligation being overstated and GOB revenue being understated. See note 2 of the Corporation's annual audited consolidated financial statements.

Other finance expenses for 2013 included accretion on decommissioning obligations of $4.4 million (2012 - $4.8 million) and a loss of $1.3 million (2012 - $47,000) related to the expiry and partial exercise of Perpetual's option to repurchase up to a 30 percent interest in WGS LP. A loss of $0.1 million was also realized on marketable securities sold during the fourth quarter of 2013 (2012 – gain of $0.8 million) related to the sale of TriOil shares for cash proceeds of $1.9 million.

Funds flow

	2013		2012	
	($ thousands)	**($/boe)**	($ thousands)	($/boe)
Realized revenue (1)	**208,522**	**30.56**	203,359	27.58
Royalties	**(19,042)**	**(2.79)**	(12,665)	(1.72)
Operating expenses	**(75,414)**	**(11.05)**	(79,709)	(10.81)
Transportation costs	**(10,163)**	**(1.49)**	(8,773)	(1.19)
Operating netback (1)	**103,903**	**15.23**	102,212	13.86
GOB revenue (2)	**8,905**	**1.30**	6,768	0.92
Exploration and evaluation (3)	**(3,269)**	**(0.48)**	(3,424)	(0.46)
Cash G&A	**(24,509)**	**(3.59)**	(27,124)	(3.68)
Interest (3)	**(28,932)**	**(4.24)**	(32,483)	(4.41)
Dividends from WGS LP	**2,370**	**0.35**	910	0.12
Gas storage operating netback (4)	**–**	**–**	2,228	0.30
Funds flow (1)	**58,468**	**8.57**	49,087	6.65

(1) See "Non-GAAP measures" in this MD&A.

(2) Prior period amounts have been restated as a result of the GOB obligation being overstated and GOB revenue being understated. See note 2 of the Corporation's annual audited consolidated financial statements.

(3) Excludes non-cash items.

(4) 2012 gas storage operating netback includes gas storage revenue net of operating expenses. Revenue and expenses related to the operation of the gas storage business were no longer accounted for on a consolidated basis after April 25, 2012.

Funds flow increased 19 percent to $58.5 million ($0.39 per share) for the year ended December 31, 2013 as compared to $49.1 million ($0.33 per share) for the same period in 2012 reflecting the increase in the operating netback, GOB royalty adjustments and dividends from WGS LP combined with a reduction in G&A and interest expense in 2013.

Net income (loss)

	2013		2012	
	($ thousands)	**($/boe)**	($ thousands)	($/boe)
Funds flow (1)	**58,468**	**8.57**	49,087	6.65
Unrealized gains (losses) on derivatives	**1,783**	**0.26**	(2,224)	(0.30)
Call option premiums received	**(953)**	**(0.14)**	(2,446)	(0.33)
Exploration and evaluation (3)	**(3,994)**	**(0.59)**	(5,858)	(0.79)
Compensation expense, non-cash	**(3,974)**	**(0.58)**	(4,349)	(0.59)
Gain on dispositions	**52,143**	**7.64**	48,990	6.65
Impairment reversal (write-down)	**5,171**	**0.76**	(54,313)	(7.37)
Depletion and depreciation	**(92,877)**	**(13.61)**	(105,667)	(14.33)
Financial items, non-cash (2)	**(9,566)**	**(1.40)**	(1,477)	(0.20)
WGS LP net income (loss) and dividends	**1,419**	**0.21**	(1,482)	(0.20)
Deferred income tax benefit	**–**	**–**	3,753	0.51
Net income (loss)	**7,620**	**1.12**	(75,986)	(10.30)

(1) See "Non-GAAP measures" in this MD&A.

(2) Prior period amounts have been restated as a result of the GOB obligation being overstated and GOB revenue being understated. See note 2 of the Corporation's annual audited consolidated financial statements.

(3) Includes non-cash exploration and evaluation expense from expired leases and geological and geophysical costs.

The Corporation recorded net income of $7.6 million ($1.12 per boe) for the year ended December 31, 2013 compared to a net loss of $76.0 million ($10.30 per boe) for the prior year.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q4 2013**	Q3 2013	Q2 2013	Q1 2013
Financial				
Oil and natural gas revenues	**49,075**	52,555	57,187	42,477
Funds flow [(1)]	**12,998**	18,650	17,286	9,534
Per share – basic	**0.09**	0.13	0.12	0.06
Net income (loss) [(2)]	**(13,745)**	(6,833)	(4,566)	32,764
Per share – basic [(2)]	**(0.09)**	(0.05)	(0.03)	0.22
– diluted [(2)]	**(0.09)**	(0.05)	(0.03)	0.21
Capital expenditures				
Exploration and development	**24,518**	22,350	10,360	39,456
Acquisitions	**418**	532	5,433	1,752
Dispositions	**(901)**	(60)	(84)	(77,930)
Interest in WGS LP	**–**	–	19,129	–
Other	**2**	34	33	51
Net capital expenditures	**24,037**	22,856	34,871	(36,671)
Operating				
Daily average production				
Natural gas (MMcf/d)	**90.3**	85.3	91.9	88.6
Oil and NGL (boe/d)	**3,509**	4,064	4,384	3,483
Total (boe/d)	**18,559**	18,274	19,708	18,244
Average prices				
Natural gas – before derivatives ($/Mcf)	**3.37**	2.79	3.68	3.18
Natural gas – including derivatives ($/Mcf)	**3.62**	3.31	3.90	3.28
Oil and NGL – before derivatives ($/bbl)	**65.35**	82.03	66.18	54.74
Oil and NGL – including derivatives ($/bbl)	**65.88**	76.86	64.84	56.82

($ thousands, except as noted)	Q4 2012	Q3 2012	Q2 2012	Q1 2012
Financial				
Oil and natural gas revenues	44,468	40,028	40,444	51,197
Funds flow [(1)]	11,158	10,760	12,668	14,501
Per share – basic	0.08	0.07	0.09	0.10
Net income (loss) [(2)]	(56,400)	(34,117)	26,511	(11,980)
Per share – basic [(2)]	(0.38)	(0.22)	0.18	(0.08)
– diluted [(2)]	(0.38)	(0.22)	0.17	(0.08)
Capital expenditures				
Exploration and development	21,185	17,922	9,606	31,011
Acquisitions	–	1,709	–	698
Dispositions	(6,923)	(16,207)	(80,650)	(63,390)
Other	23	44	14	190
Net capital expenditures	14,285	3,468	(71,030)	(31,491)
Operating				
Daily average production				
Natural gas (MMcf/d)	88.3	93.7	105.1	113.7
Oil and NGL (boe/d)	3,536	3,336	3,446	3,474
Total (boe/d)	18,250	18,955	20,962	22,428
Average prices				
Natural gas – before derivatives ($/Mcf)	2.99	2.36	2.12	2.50
Natural gas – including derivatives ($/Mcf)	3.56	3.44	3.28	3.13
Oil and NGL – before derivatives ($/bbl)	62.02	64.24	61.10	69.70
Oil and NGL – including derivatives ($/bbl)	71.29	59.63	58.58	66.60

(1) See "Non-GAAP measures" in this MD&A.

(2) Prior period amounts have been restated as a result of the GOB obligation being overstated and GOB revenue being understated. See note 2 of the Corporation's annual audited consolidated financial statements.

Oil and natural gas revenues are a function of production levels and oil and natural gas prices. Revenues were lowest in the third quarter of 2012 due to low AECO Monthly Index prices combined with reduced natural gas production compared to previous quarters as well as slightly lower oil prices. In addition, beginning on April 25, 2012, no WGS LP revenue was consolidated within oil and natural gas revenues due to the Corporation's investment in WGS LP being accounted for as an equity-method investment. Revenues increased considerably during the second and third quarters of 2013 with increased oil and NGL production and higher commodity prices. Oil production declines from the third quarter to the fourth quarter of 2013 related to capital being redirected to Edson facilities until late 2013 when drilling in Mannville recommenced with a one rig winter program.

Perpetual uses derivatives to mitigate the effect of volatility in oil and natural gas prices on funds flows. In addition, Perpetual has been successfully executing an asset base transformation and commodity diversification strategy to enhance the corporate production base with higher-priced oil and NGL volumes. The impact of non-core asset dispositions and application of cost saving initiatives have resulted in a lower cost structure moving from 2012 through 2013. Funds flows will trend with Perpetual's production mix, realized commodity prices and changes in production levels. Consistent with revenues, funds flows were highest in the third quarter of 2013 and lowest in the first quarter of 2013.

Net income (loss) is a function of funds flows and non-cash charges such as depletion, impairment losses, gains and losses on asset dispositions and unrealized gains (losses) on derivatives. Due to the volatility of natural gas prices and the Corporation's risk management position, net income (loss) also fluctuate with changes in forward commodity prices as of each balance sheet date. Perpetual has incurred net losses in most quarters presented as a result of persistently low natural gas prices during the two-year period. The largest net loss was in the fourth quarter of 2012, due in part to an impairment charge of $54.3 million resulting from reserve reductions at year end due to low natural gas prices. The Corporation reported net income of $32.8 million in the first quarter of 2013 as a result of a gain on the disposition of Elmworth and $26.5 million in the second quarter of 2012 as a result of a $40.6 million gain on sale of 90 percent of WGS LP.

FOURTH QUARTER FINANCIAL AND OPERATING RESULTS

The Corporation continued its focus on liquids-rich natural gas at Edson and Mannville heavy oil during the fourth quarter of 2013 with four (2.0 net) horizontal wells drilled at West Edson and five (5.0 net) horizontal wells drilled in Mannville. Two (1.0 net) of the West Edson liquids-rich gas wells and one (1.0 net) of the Mannville heavy oil wells came on production late in December 2013. The remainder of these new wells started production after completion and tie in operations were finished in late January 2014. In addition, a waterflood pilot project at Mannville was successfully started up during the fourth quarter of 2013. Total capital expenditures of $24.5 million were spent on fourth quarter capital projects.

Perpetual's fourth quarter 2013 total production of 18,559 boe/d was marginally higher than the comparative fourth quarter of 2012 (18,250 boe/d) with new production from a successful 2013 drilling program more than offsetting natural declines. Deemed production decreased 23 percent reflecting the annual decline of 10 percent as well as the termination of compensation for certain wells reaching their 10 year maximum period.

Revenue declined slightly during the fourth quarter of 2013 compared to the same period in 2012 due to decreased realized economic hedging gains which were partially offset by increased prices on natural gas and increased oil and NGL production. Slight decreases in revenue were offset by lower operating expenses, which together with dividends received from Perpetual's 30 percent interest in WGS LP, resulted in $13.0 million in funds flow for the fourth quarter of 2013, up 16 percent from the fourth quarter of 2012. A net loss of $13.7 million ($0.09 per share) was recorded for the fourth quarter of 2013.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

($ thousands, except as noted)	**2013**	2012
Bank debt	**70,618**	77,974
Senior notes, measured at principal amount	**150,000**	150,000
Convertible debentures, measured at principal amount	**159,779**	159,972
Adjusted working capital surplus (1)	**(3,417)**	(147)
Net debt	**376,980**	387,799
Shares outstanding at end of period (thousands)	**148,490**	147,455
Market price at end of period	**1.11**	1.15
Market value of shares	**164,824**	169,573
Total capitalization (1)	**541,804**	557,372
Net debt as a percentage of total capitalization	**69.6**	69.6
Funds flow (1)	**58,468**	49,087
Net debt to funds flow ratio (times) (2)	**6.4**	7.9

(1) See "Non-GAAP measures" in this MD&A.

(2) Net debt to funds flow is calculated based on trailing funds flow for the most recent four quarters.

The Corporation's 7.25 percent convertible debentures (7.25% Debentures) and 7.0 percent convertible debentures (7.0% Debentures) mature on January 31, 2015 and December 31, 2015 respectively. While the Corporation has the option to settle all or a portion of the outstanding 7.25% Debentures and 7.00% Debentures through the issuance of shares by giving notice of such intent to debenture holders not more than 60 and not less than 30 days prior to the maturity date, it is the intention of the Corporation to settle in cash. The banks for the Corporation's revolving credit facility are awaiting more certainty on the Corporation's plans to settle the debenture prior to extending the revolving credit facility which, if not renewed, comes due in October 31, 2014. The Corporation will apply to have the facility renewed prior to the next semi-annual review on April 30, 2014. In advance of the facility coming due, management plans include pursing alternative financing arrangements on the facility based on the Corporation's increased year-over-year externally evaluated reserve values.

Management is pursuing repayment options for the 7.25% Debentures and 7.00% Debentures including asset dispositions, refinancing, or a combination thereof. There is no assurance that the Corporation will be able raise additional capital to settle all or a portion of the outstanding 7.25% Debentures and 7.00% Debentures in cash, in which case, the Corporation would have the option to settle all or a portion of the debentures through the issuance of shares.

Bank debt and working capital

The Corporation targets 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 of 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. As at December 31, 2013, the Corporation's ratio of net debt to funds flow decreased 19 percent to 6.4 to 1 (December 31, 2012 – 7.9 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 or dispositions, 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.

At December 31, 2013, Perpetual had $70.6 million outstanding on its credit facility, down $7.4 million from December 31, 2012 ($78.0 million), as proceeds from property dispositions, net of acquisitions, of $70.8 million were applied against outstanding bank debt in 2013. Capital expenditures of $96.7 million and the $19.1 million purchase of an additional 20 percent interest in WGS LP were funded by funds flow of $58.5 million with the balance funded through net property disposition proceeds.

Perpetual's adjusted working capital surplus at December 31, 2013 was $3.4 million compared to a surplus of $0.1 million at December 31, 2012. The Corporation has an adjusted working capital surplus primarily due to Crown receivables from GOB royalty adjustments. Working capital deficiencies will be funded from future sales revenues and by additional credit facility borrowings as required.

The Corporation's credit facility is with a syndicate of Canadian chartered banks. On April 26, 2013, the Corporation's lenders completed their semi-annual review of the borrowing base under the credit facility. The total availability under the credit facility was reduced to $110 million on July 31, 2013, including a demand loan of $95 million and a working capital facility of $15 million. The reduction from the previous borrowing base of $125.0 million was due to dispositions and lower natural gas price forecasts used in lender evaluations, offset by increased lending values attributable to higher oil and NGL reserves.

On October 31, 2013, the Corporation's lenders completed their semi-annual review of the borrowing base under the credit facility. The total availability under the credit facility remains at $110 million which includes a demand loan of $95 million and a working capital facility of $15 million. The revolving nature of the credit facility has been extended to October 30, 2014. The next semi-annual redetermination of the Corporation's borrowing base will occur on or before April 30, 2014.

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.

Reconciliation of net debt

($ millions)	
Net debt, December 31, 2012 (1) (2)	387.8
Capital expenditures (3)	96.8
Dispositions, net of acquisitions	(70.8)
Funds flow (2)	(58.5)
Purchase of interest in WGS LP	19.1
Loss on marketable securities	0.1
Expenditures on decommissioning obligations	2.5
Net debt, December 31, 2013 (2)	377.0

(1) Prior period amounts have been restated as a result of the GOB obligation being overstated and GOB revenue being understated. See note 2 of the Corporation's annual audited consolidated financial statements.

(2) See "Non-GAAP measures" in this MD&A.

(3) Capital expenditures consist of exploration and development and other.

Senior notes

At December 31 2013, Perpetual had $150 million of senior notes outstanding which mature on March 15, 2018 and bear interest at 8.75 percent, payable semi-annually. 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 are carried on the statement of financial position at the par value less unamortized debt issue costs. The fair value of the senior notes at March 5, 2014 was $150.4 million.

As part of the senior notes indenture and the credit facility, the Corporation has covenants that require the ratios of consolidated debt and consolidated senior debt to 12 month trailing income before interest, taxes and depletion and depreciation to be less than 4 to 1 and 3 to 1, respectively. Consolidated debt is defined as the sum of the balance on the credit facility, senior notes and outstanding letters of credit. Consolidated senior debt is defined as consolidated debt less the senior notes. Perpetual was in compliance with these covenants at December 31, 2013. The senior notes indenture also contains restrictions on certain payments including dividends, retirement of subordinated debt and stock repurchases. Allowable payments are increased by 50 percent of cash flow from operating activities and reduced by restricted payments.

Convertible debentures

At December 31, 2013, the Corporation has outstanding 7.25% Debentures that mature on January 31, 2015 as well as 7.0% Debentures that mature on December 31, 2015. In June 2013, Perpetual initiated a Normal Course Issuer Bid to purchase a portion of the outstanding convertible debentures for cancellation subject to Toronto Stock Exchange restrictions. At the end of the second quarter and beginning of the third quarter of 2013, the Corporation purchased and cancelled 71,000 7.25% Debentures and 122,000 7.0% Debentures for a total cash outlay of $0.2 million. All series of convertible debentures are repayable on the maturity date in cash or in shares, at the option of Perpetual. Additional information on convertible debentures is as follows:

Convertible debentures

($ millions, except as noted)	7.25%	7.00%
Principal issued	100.0	60.0
Principal outstanding	99.9	59.9
Trading symbol on the Toronto Stock Exchange	PMT.DB.D	PMT.DB.E
Maturity date	January 31, 2015	December 31, 2015
Conversion price ($ per share)	7.50	7.00
Fair market value (1)	99.1	59.0

(1) Fair values of debentures are calculated by multiplying the number of debentures outstanding at March 5, 2014 by the quoted market price per debenture at that date.

Equity

Perpetual's total capitalization was $541.8 million at December 31, 2013. Net debt to total capitalization remained at 70 percent at December 31, 2013 as compared to December 31, 2012. Decreased market value of Perpetual's shares offset reductions made to net debt during 2013. Reductions to net debt were achieved with proceeds from the disposition of Elmworth and funds flow generated from operations which were partially offset by capital expenditures and acquisitions.

Weighted average shares outstanding for the year ended December 31, 2013 totaled 148.1 million (2012 – 147.1 million). On March 5, 2014 there were 148.5 million shares outstanding.

2014 OUTLOOK

Perpetual's strategic priorities for 2014 are as follows:

- Reduce debt and manage downside risks;
- Grow Edson liquids-rich gas production, reserves, cash flow, inventory and value;
- Maximize value of Mannville heavy oil;
- Maximize cash flow from shallow gas; and
- Advance and broaden portfolio of high impact opportunities with risk-managed investment.

Perpetual continues to target capital spending in 2014 to be fully funded by 2014 funds flow. The Corporation's Board of Directors has approved a $70 to $80 million capital budget for full calendar year 2014. First quarter spending is on track to be approximately $35 million. The table below summarizes planned drilling activities in accordance with Perpetual's 2014 strategic priorities.

2014 Capital budget

($ millions, except as noted)	Q1	# Wells	Q2 – Q4	# Wells
West Central liquids-rich gas	18	3 (2.0 net)	21 – 26	up to 7 (3.5 net)
Mannville heavy oil	13	11 (9.7 net)	11 – 14	up to 12 (8.3 net)
Shallow gas	4	–	3 - 5	–
Total	35	14 (11.7 net)	35 - 45	19 (11.8 net)

In addition to drilling activities, Perpetual plans to allocate a portion of its 2014 budget to install additional plant and compression equipment at its West Edson facility in order to increase plant capacity to accommodate expected incremental production associated with the West Central drilling program. The capital budget also includes activities focused on maximizing value and mitigating production declines on the Corporation's legacy shallow gas assets through facility optimization projects, workovers and uphole recompletions.

Perpetual estimates that 2014 funds flow will total $80 to $90 million based on current forward commodity prices with oil and liquids production averaging close to 3,400 – 3,500 bbl/d and natural gas sales averaging approximately 90 to 95 MMcf/d. The enhanced heat content of Perpetual's liquids-rich gas in West Central Alberta results in premium pricing to AECO market prices.

Sensitivities

Below is a table that shows sensitivities of Perpetual's 2014 forecasted funds flow to operational changes and changes in the business environment:

($ millions, except as noted) (1)	Change in remainder of 2014 (March to December)	Estimated impact on 2014 funds flow
Business Environment		
Natural gas price at AECO (2)	$0.25/Mcf	2.5
Oil price at WTI (2) (3)	$US5.00/bbl	0.7
WTI – WCS differential (2)	$US5.00/bbl	3.0
Interest rate on bank debt	1%	(0.7)
Operational		
Natural gas production	5 MMcf/d	6.2
Oil and NGL production	100 bbl/d	1.9
Operating expenses	$0.50/boe	(3.0)

(1) Base funds flow estimate assumes average March through December forward market prices of WTI $US97.63/bbl; WTI-WCS differential $US22.43/bbl; and AECO $4.68/GJ.

(2) Giving effect to commodity price risk management contracts in place at March 5, 2014.

(3) Reflects positive change in price; a $US5.00 decrease in WTI would result in a decrease of $1.8 million in funds flow.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

At December 31, 2013, Perpetual has operating lease commitments under office lease costs and related sublease recoveries through to March 31, 2018. Perpetual also has long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada. As of December 31, 2013, the future minimum payments under these commitments consisted of:

($ thousands)	Pipeline commitments	Operating lease commitments
2014	4,599	1,743
2015	1,682	1,678
2016	94	1,661
2017	34	1,598
2018	24	399
Total	6,433	7,079

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

CORPORATE GOVERNANCE

The Corporation is committed to maintaining high standards of corporate governance. Each regulatory body, including the Toronto Stock Exchange and the Canadian provincial securities commissions, 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.

RISK FACTORS

The business risks the Corporation is exposed to are those inherent in the oil and gas industry as well as those governed by the individual nature of Perpetual's operations, Risks impacting the business which influence controls and management of the Corporation include, but are not limited to, the following:

- Geological and engineering risks;
- The uncertainty of discovering commercial quantities of new reserves;
- Commodity prices, interest rate and foreign exchange risks;
- Competition; and
- Changes to government regulations including shut in of GOB assets.

Perpetual manages these risks by:

- Attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the corporation;
- Operating properties in order to maximize opportunities;
- Employing risk management instruments and policies to minimize exposure to volatility of commodity prices, interest rates and foreign exchange rates;
- Maintaining a strong financial position;
- Maintaining strict environment, safety and health practices.

A complete discussion of risk factors is included in the Corporation's 2013 AIF located at www.sedar.com.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Perpetual's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") and Internal controls over financial reporting ("ICOFR") as defined in National Instrument 52-109 Certification of Disclosure in Issuer's Annual and Interim Filings in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS.

Disclosure Controls and Procedures

The DC&P have been designed to provide reasonable assurance that material information relating to Perpetual is made known to the CEO and CFO by others and that information required to be disclosed by Perpetual in its annual filings, interim filing or other reports filed or submitted by Perpetual under securities legislation.

Perpetual's CEO and CFO have concluded, based on their evaluation at December 31, 2013, that DC&P are effective to provide reasonable assurance that material information related to the issuer is made known to them by others within the Corporation, as such information is recorded, processed, summarized and reported in the reports we file or send to securities regulatory authorities within the time periods specified under Canadian securities laws.

Management's annual report on ICOFR

Management is responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, the CEO and CFO, and effected by the Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including the CEO and CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2013 based on criteria described in "Internal Control – Integrated Framework" issued in 1992 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2013, the internal control over financial reporting was effective.

Changes to internal control over financial reporting

As disclosed in note 2 to the consolidated financial statements, Perpetual restated the 2012 comparative figures with respect to accounting for GOB royalty adjustments. Due to the non-routine nature of the GOB royalty adjustments, this is a specific area of accounting for which there is limited guidance on accounting for obligations to repay some or all of the royalty adjustments received. Management designed a new control in the fourth quarter of 2013 which included modifying Perpetual's methodology for recognition of the royalty adjustments as well as the obligation to repay some of the royalty adjustments received. The financial reporting group incorporated the new control into their processes as well as the methodology for recording royalty adjustments and associated obligations for repayment. No other changes in Perpetual's ICOFR were made during the quarter ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, ICOFR.

CEO and CFO certifications

Perpetual's CEO and CFO have filed with the Canadian securities regulators regarding the quality of Perpetual's public disclosures relating to its fiscal 2013 report filed with the Canadian securities regulators.

CRITICAL ACCOUNTING ESTIMATES

Perpetual makes assumptions in applying certain critical accounting estimates that are uncertain at the time the accounting estimate is made and may have a significant effect on the consolidated financial statements. Critical accounting estimates include oil and natural gas reserves, derivative financial instruments, provisions, the amount and likelihood of contingent liabilities and income taxes. Critical accounting estimates are based on variable inputs including:

- Estimation of recoverable oil and natural gas reserves and future cash flows from reserves;
- Forward market price curves;
- Geological interpretations, success or failure of exploration activities, and Perpetual's plans with respect to property and financial ability to hold the property;
- Risk free interest rates;
- Estimation of future abandonment and reclamation costs;
- Facts and circumstances supporting the likelihood and amount of contingent liabilities; and
- Interpretation of income tax laws.

A change in a critical accounting estimate can have a significant effect on net income as a result of their impact on the depletion rate, provisions, impairments, losses and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant, and equipment, provisions, derivative financial instruments and accounts payable. A complete discussion of critical accounting estimates is included in the notes to the consolidated financial statements at December 31, 2013.

Future accounting pronouncements

The International Accounting Standards Board ("IASB") and the IFRS Interpretations Committee regularly issue new and revised accounting pronouncements which have future effective dates and therefore are not reflected in Perpetual's financial statements. Once adopted these new and amended pronouncements may have an impact on Perpetual's consolidated financial statements. Perpetual's analysis of recent accounting pronouncements is included in the notes to the consolidated financial statements at December 31, 2013.

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 IFRS 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 2013 to 2012 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.

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, 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 5, 2014

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, 2013, December 31, 2012 and January 1, 2012, the consolidated statements of loss and comprehensive loss, changes in equity and cash flows for the years ended December 31, 2013 and December 31, 2012, 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 Standard, 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. 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 Corporation's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. 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, 2013, December 31, 2012 and January 1, 2012, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2013 and December 31, 2012, in accordance with International Financial Reporting Standards.

Comparative Information

Without modifying our opinion, we draw attention to note 2 to the consolidated financial statements which indicates that the comparative information presented as at and for the year ended December 31, 2012, has been restated and that the comparative information presented as at January 1, 2012, has been derived from the consolidated financial statements as at and for the year ended December 31, 2011.

KPMG LLP

Chartered Accountants

Calgary, Canada

March 5, 2014

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
(Cdn$ thousands)		Restated (note 2)	Restated (note 2)
Assets			
Current assets			
Accounts receivable	**$ 36,099**	$ 33,787	$ 34,209
Prepaid expenses and deposits	**1,369**	2,928	3,891
Marketable securities	**–**	1,963	3,282
Derivatives (note 18)	**326**	3,703	12,604
Assets held for sale (note 5)	**–**	22,321	20,325
	37,794	64,702	74,311
Long term Crown receivable (note 9)	**10,997**	8,784	9,059
Derivatives (note 18)	**19**	–	7,692
Property, plant and equipment (note 7)	**576,954**	570,415	827,928
Exploration and evaluation (note 8)	**88,177**	80,494	106,763
Equity-method investment (note 6)	**28,347**	5,493	–
	704,494	665,186	951,442
Total assets	**$ 742,288**	$ 729,888	$ 1,025,753
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities	**$ 45,048**	$ 47,315	$ 53,316
Derivatives (note 18)	**6,468**	1,452	6,841
Share based payment liability	**11**	24	664
Convertible debentures (note 12)	**–**	–	74,250
Bank indebtedness (note 10)	**70,618**	–	–
Liabilities associated with assets held for sale (note 5)	**–**	93	4,843
	122,145	48,884	139,914
Derivatives (note 18)	**2,778**	8,402	10,865
Bank indebtedness (note 10)	**–**	77,974	130,062
Senior notes (note 11)	**147,719**	147,177	146,634
Convertible debentures (note 12)	**154,496**	151,673	149,020
Gas storage obligation	**–**	–	41,630
Gas over bitumen obligation (note 13)	**2,948**	2,737	3,356
Decommissioning obligation (note 13)	**213,906**	206,379	242,860
Deferred tax liability (note 21)	**–**	–	3,753
	521,847	594,342	728,180
Total liabilities	**643,992**	643,226	868,094
Equity			
Share capital (note 14)	**1,257,315**	1,255,450	1,254,273
Equity component of convertible debentures	**13,971**	13,988	13,988
Contributed surplus	**21,474**	19,308	15,496
Deficit	**(1,194,464)**	(1,202,084)	(1,126,098)
Total equity	**98,296**	86,662	157,659
Total liabilities and equity	**$ 742,288**	$ 729,888	$ 1,025,753

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 INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

		Year ended December 31
	2013	2012
(Cdn$ thousands, except per share amounts)		Restated (note 2)
Revenue		
Oil and natural gas	**$ 201,294**	$ 176,137
Royalties	**(19,042)**	(12,665)
	182,252	163,472
Change in fair value of commodity price derivatives (note 18)	**8,058**	26,811
Gas over bitumen (note 4h)	**8,905**	6,768
	199,215	197,051
Expenses		
Production and operating	**75,414**	81,740
Transportation	**10,163**	8,773
Exploration and evaluation (note 8)	**7,263**	9,282
General and administrative	**28,483**	31,473
Gain on dispositions (notes 5 and 7)	**(52,143)**	(48,990)
Depletion and depreciation (note 7)	**92,877**	105,667
Impairment (reversals) losses (note 7)	**(5,171)**	54,313
Income (loss) from operating activities	**42,329**	(45,207)
Finance expenses (note 16)	**(38,498)**	(33,960)
Share of net income (loss) of equity-method investment (note 6)	**3,789**	(572)
Income (loss) before tax	**7,620**	(79,739)
Deferred income tax benefit (note 21)	**–**	3,753
Net income (loss) and comprehensive income (loss)	**$ 7,620**	$ (75,986)
Income (loss) per share (note 14)		
Basic and diluted	**$ 0.05**	$ (0.52)

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 Restated (note 2)	Total equity
Balance at December 31, 2012	$ 1,255,450	$ 13,988	$ 19,308	$ (1,202,084)	$ 86,662
Net income	–	–	–	7,620	7,620
Common shares issued pursuant to share based compensation plans	1,865	–	(1,838)	–	27
Share based compensation expense	–	–	3,974	–	3,974
Share based payment liability	–	–	13	–	13
Redemption of convertible debentures	–	(17)	17	–	–
Balance at December 31, 2013	**$ 1,257,315**	**$ 13,971**	**$ 21,474**	**$ (1,194,464)**	**$ 98,296**

(Cdn$ thousands)	Share capital	Equity component of convertible debentures	Contributed surplus	Deficit Restated (note 2)	Total equity
Balance at January 1, 2012	$ 1,254,273	$ 13,988	$ 15,496	$ (1,126,098)	$ 157,659
Net loss	–	–	–	(75,986)	(75,986)
Common shares issued pursuant to share based compensation plans	1,177	–	(1,177)	–	–
Share based compensation expense	–	–	4,349	–	4,349
Share based payment liability	–	–	640	–	640
Balance at December 31, 2012	$ 1,255,450	$ 13,988	$ 19,308	$ (1,202,084)	$ 86,662

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Cdn$ thousands)	Year ended December 31 2013	2012 Restated (note 2)
Cash flows from operating activities		
Net income (loss)	**$ 7,620**	$ (75,986)
Adjustments to add (deduct) non-cash items:		
Depletion and depreciation	**92,877**	105,667
Exploration and evaluation	**2,715**	5,758
Share based compensation expense	**3,974**	4,349
Change in fair value of commodity price derivatives	**(1,783)**	2,224
Finance expenses	**9,566**	1,477
Share of net (income) loss of equity-method investment	**(3,789)**	572
Deferred income tax benefit	**–**	(3,753)
Gain on dispositions	**(52,143)**	(48,990)
Impairment (reversals) losses	**(5,171)**	54,313
Share of dividends from equity-method investment (note 6)	**2,370**	910
Call option premiums received	**953**	2,446
Long-term Crown receivable adjustments	**(2,213)**	275
Expenditures on decommissioning obligations	**(2,497)**	(1,825)
Change in non-cash working capital (note 17)	**(146)**	1,162
Net cash from operating activities	**52,333**	48,599
Cash flows used in financing activities		
Change in bank indebtedness	**(7,356)**	(52,844)
Repayment of convertible debentures	**(187)**	(74,925)
Common shares issued net of issue fees	**27**	–
Change in non-cash working capital (note 17)	**(20)**	33
Net cash used in financing activities	**(7,536)**	(127,736)
Cash flows from (used in) investing activities		
Acquisitions	**(8,255)**	(2,627)
Capital expenditures	**(95,405)**	(79,675)
Proceeds on dispositions	**78,975**	167,170
Proceeds on sale of marketable securities	**1,871**	2,120
Increased interest in equity-method investment	**(19,129)**	–
Change in non-cash working capital (note 17)	**(2,854)**	(7,851)
Net cash from (used in) investing activities	**(44,797)**	79,137
Change in cash	**–**	–
Cash, beginning of year	**–**	–
Cash, end of year	**$ –**	$ –
Interest paid	**$ 29,220**	$ 32,468

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

Perpetual Energy Inc. ("Perpetual" or the "Corporation") is a Canadian corporation engaged in the exploration, development, and marketing of oil and gas based energy in Alberta, Canada. The Corporation operates a diversified asset portfolio that includes conventional heavy oil, resource-style tight gas, liquids rich gas in the Alberta deep basin, and several long-term bitumen resource properties.

The address of the Corporation's registered office is 3200, 605 – 5 Avenue S.W., Calgary, Alberta, T2P 3H5.

The consolidated financial statements of the Corporation are comprised of the accounts of Perpetual and its wholly owned subsidiaries, Perpetual Energy Operating Corp. and Perpetual Operating Trust, which are incorporated in Canada.

2. RESTATEMENT OF PRIOR PERIOD AMOUNTS

During preparation of the consolidated financial statements for the year ended December 31, 2013, Perpetual determined that:

i) The gas over bitumen obligation (see notes 4(h) and 13) as at January 1 and December 31, 2012 was overstated when compared to the present value of expected repayments of the gas over bitumen royalty adjustments received by the Corporation under the Natural Gas Royalty Regulation (2002) with respect to foregone production from gas wells shut-in for the benefit of bitumen producers in the Athabasca oil sands area. Previously, the Corporation recognized the undiscounted amount of the gas over bitumen royalty adjustment, net of any amounts receivable, as gas over bitumen obligation.

ii) As a result of recording the gas over bitumen royalty adjustments received or due as an obligation, the gas over bitumen revenue was understated for the year ended December 31, 2012 and prior years. Previously, no gas over bitumen revenue was recognized unless it related to shut-in wells that had been sold, where entitlement to the royalty adjustment was retained but the obligation for repayment had been transferred to the purchaser.

The effect of the restatement on the consolidated statement of financial position as at January 1 and December 31, 2012 is as follows:

			January 1, 2012			December 31, 2012
	As reported	Adjustments	Restated	As reported	Adjustments	Restated
Long-term Crown receivable (note 9)	–	9,059	9,059	–	8,784	8,784
Gas over bitumen obligation (note 13)	74,705	(71,349)	3,356	44,553	(41,816)	2,737
Deficit	(1,206,506)	80,408	(1,126,098)	(1,252,684)	50,600	(1,202,084)

The effect of the restatement on the consolidated statement of loss and comprehensive loss for the year ended December 31, 2012 is as follows:

			Year ended December 31, 2012
	As reported	Adjustments	Restated
Gas over bitumen revenue	37,195	(30,427)	6,768
Finance expense (note 16)	(34,579)	619	(33,960)
Net loss	(46,178)	(29,808)	(75,986)
Net loss per share – basic and diluted	(0.31)	(0.21)	(0.52)

3. BASIS OF PREPARATION

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements of the Corporation were approved and authorized for issue by the Board of Directors on March 5, 2014.

The consolidated financial statements have been prepared on a historical cost basis except for marketable securities and derivative financial instruments that have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Corporation and its subsidiaries.

Critical accounting judgments and significant estimates

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. These judgments, estimates, and assumptions are continuously evaluated and are based on management's experience and all relevant information available to the Corporation at the time of financial statement preparation. As the effect of future events cannot be determined with certainty the actual results may differ from estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Information about the critical judgments and significant estimates made by management are described below and also in the relevant notes to the financial statements.

Critical accounting judgments:

The following are the critical judgments that management has made in the process of applying the Corporation's accounting policies. These judgments have the most significant effect on the amounts reported in the consolidated financial statements.

i) Cash-generating units

The Corporation allocates its oil and natural gas properties to cash generating units ("CGUs") identified as the smallest group of assets that generate cash flows independent of the cash flows of other assets or groups of assets. Determination of the CGUs is subject to management's judgement and is based on geographical proximity, shared infrastructure, and similar exposure to market risk.

ii) Componentization

For the purposes of depletion the Corporation allocates its oil and natural assets to components with similar useful lives and depletion methods. The grouping of assets is subject to management's judgement and is performed on the basis of geographical proximity and similar reserve life. The Corporation's oil and gas assets are depleted on a unit of production basis.

iii) Exploration and evaluation expenditures

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as exploration and evaluation ("E&E") assets pending determination of technical feasibility and commercial viability. Establishment of technical feasibility and commercial viability is subject to judgement and involves management's review of project economics, resource quantities, expected production techniques, production costs and required capital expenditures to confirm continued intent to develop and extract the underlying resources. Management uses the establishment of commercial reserves within the exploration area as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets attributable to those reserves are tested for impairment and reclassified from E&E assets to a separate category within tangible assets referred to as oil and natural gas properties.

iv) Joint arrangements

Judgement is required to determine when the Corporation has joint control over an arrangement. In establishing joint control the Corporation considers whether unanimous consent is required to direct the activities that significantly affect the returns of the arrangement, such as the capital and operating activities of the arrangement.

Once joint control has been established judgement is also required to classify a joint arrangement. The type of joint arrangement is determined through analysis of the rights and obligations arising from the arrangement by considering its structure, legal form, and terms agreed upon by the parties sharing control. An arrangement where the controlling parties have rights to the assets and revenues, and obligations for the liabilities and expenses, is classified as a joint operation. Arrangements where the controlling parties have rights to the net assets of the arrangement are classified as joint ventures.

Significant estimates:

The following assumptions represent the key sources of estimation uncertainty at the end of the reporting period. As future confirming events occur the actual results may differ from estimated amounts.

i) Reserves

The Corporation uses estimates of natural gas, oil, and liquids reserves in the calculation of depletion and also for value in use and fair value less costs to sell ("FVLCS") calculations of non-financial assets. Estimates of economically recoverable natural gas, oil, and liquids reserves and their future net cash flows are based upon a number of variable factors and assumptions, such as geological, geophysical, and engineering assessments of hydrocarbons in place on the Corporation's lands, historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by government agencies and future operating costs. The geological, economic and technical factors used to estimate reserves may change from period to period. Changes in the reported reserves could have a material impact on the carrying values of the Corporation's oil and natural gas properties, the calculation of depletion and depreciation and the timing of decommissioning cash flows.

Reserve engineers are engaged at least annually to independently evaluate the recoverable quantities and estimated future cash flows from the Corporation's interest in petroleum and natural gas properties. This evaluation of proved and proved plus probable reserves is prepared in accordance with the reserve definitions contained in National Instrument 51-101 and the COGE Handbook.

ii) Provisions for decommissioning obligations

Decommissioning, abandonment, and site reclamation expenditures for production facilities, wells and pipelines are expected to be incurred by the Corporation over many years into the future. Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of the extent and timing of decommissioning activities, future site remediation regulations and technologies, inflation and liability specific discount rates, and the related cash flows. The provision represents management's best estimate of the present value of the future abandonment and reclamation costs required. Actual abandonment and reclamation costs could be materially different from estimated amounts.

iii) Derivative financial instruments

Derivatives are measured at fair value on each reporting date. Fair value is the price that would be received or paid to exit the position as of the measurement date. The Corporation uses estimated external forward market price curves available at period end and the contracted volumes over the contracted term to determine the fair value of each contract. Changes in market pricing between period end and settlement of the derivative contracts could have a material impact on financial results related to the derivatives.

4. 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, its subsidiaries, and its equity method investee.

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 are currently 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 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 acquired and liabilities assumed 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 income or loss.

iii) Joint venture

The Corporation's investment in Warwick Gas Storage Limited Partnership ("WGS LP") is accounted for as an investment in a jointly controlled entity using the equity-method of accounting.

On initial recognition of the investment, any excess of the Corporation's share of the fair value of WGS LP's net assets over the cost of the investment is included as income in the determination of the Corporation's share of WGS LP's profit or losses. The Corporation's share of WGS LP's profits or losses is recognized in net income or loss. Appropriate adjustments to the Corporation's share of WGS LP profits or losses are also made to account for depreciation of assets based on their fair values at the date of initial recognition. Dividends receivable are recognized as a reduction to the carrying amount of the investment and are included in cash flows from operating activities.

When the Corporation's cumulative share of losses equals or exceeds the Corporation's carrying amount of the investment, the Corporation does not recognize further losses unless the Corporation has incurred obligations or made payments on behalf of WGS LP.

After application of the equity-method, the Corporation determines whether it is necessary to recognize an impairment loss. Any loss recognized is recorded to net income or loss.

iv) Joint operations

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.

v) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the 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
Long term Crown receivable	Loans and receivables	Amortized cost
Marketable securities	Fair value through profit or loss	Fair value

The Corporation's accounts receivable and long term Crown 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 income 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 income 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 income or loss.

The Corporation has accounted for its forward physical delivery fixed-price sales contracts as derivative financial instruments. 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 income 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 income or loss.

iii) Non-derivative financial liabilities

Financial Instrument	Category	Subsequent Measurement
Accounts payable and accrued liabilities	Financial liabilities	Amortized cost
Long term bank debt	Financial liabilities	Amortized cost
Senior notes	Financial liabilities	Amortized cost
Convertible debentures	Financial liabilities	Amortized cost

Accounts payable and accrued liabilities, 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. If 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 income or loss. The convertible debentures are carried net of issue costs on the statement of financial position. The issue costs are amortized to net income or loss using the effective interest rate method.

iv) Share capital

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

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. 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 income or loss. The carrying amount of any replaced or disposed item of property, plant and equipment 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 income 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 income or loss as 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.

Costs associated with office furniture, information technology, and leasehold improvements are carried at cost and are depreciated on a straight line basis over a period ranging from one to three years.

Depreciation methods, useful lives and residual values are reviewed at each period end date for all classes of property, plant, and equipment.

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

Pre-license costs, geological and geophysical costs and lease rentals of undeveloped properties are recognized in net income 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 are determined, the relevant expenditure is transferred to oil and gas properties after impairment is assessed and any applicable impairment loss is recognized to net income or loss.

The Corporation's E&E assets consist solely of undeveloped land, exploratory drilling assets, 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 income or loss.

e) 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 their present condition subject to normal terms and conditions and their sale must be highly probable.

Non-current assets, or disposal groups, are measured at the lower of the carrying amount and fair value less costs to sell, with impairments recognized in net income 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.

f) 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 income or loss.

An impairment loss is reversed when there is objective evidence that the value of the financial asset has been partially or fully restored. For financial assets measured at amortized cost the reversal is recognized in net income 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. 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 and 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.

E&E assets 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. If a test is required as a result of triggering facts and circumstances, the Corporation considers whether the combined recoverable amount of oil and natural gas properties and E&E assets is sufficient to cover the combined carrying value of E&E and oil and natural gas assets after a test at the CGU level has been performed. E&E assets are tested for impairment on reclassification to oil and natural gas properties.

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 income 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 indication 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.

g) Share based payments

Awards granted under share based payment plans and agreements are equity-settled and are measured at fair value. Fair values are determined by means of an option pricing model using the exercise price of the equity instrument granted, the share price 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 costs of the equity-settled share based payments are recognized within general and administrative expenses with a corresponding increase in contributed surplus over the vesting period. Upon exercise or settlement of an equity-based instrument, consideration received and associated amounts previously recorded in contributed surplus are recorded to share capital.

h) Provisions

Provisions are recognized when the Corporation has a current legal or constructive obligation as a result of a past event, which can be reliably estimated, and will require the outflow of economic resources to settle the obligation. A provision is determined using the estimated future cash flows discounted at a rate that reflects current market conditions and liability specific risks.

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. 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 income 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.

Gas over bitumen obligation

The Corporation's entitlement to gas over bitumen royalty adjustments under the Natural Gas Royalty Regulation (2002) with respect to foregone production from gas wells shut-in (deemed production) for the benefit of bitumen producers in the Athabasca oil sands area is recognized as gas over bitumen revenue in the period that deemed production occurs.

The gas over bitumen royalty adjustment reduces the Corporation's gas Crown royalties ("royalty adjustments") otherwise payable. To the extent that royalty adjustments exceed gas Crown royalties payable in a given period, the amount is recorded as a receivable when there is reasonable assurance that it will be recovered and classified as current to the extent that the amounts are expected to be recovered within one year.

To the extent that these gas wells are allowed to return to production, the Corporation will be subject to gross overriding royalty of one percent for each year the gas over bitumen royalty adjustment was received to a maximum of 10 percent. The Corporation records a provision reflecting the present value of the expected repayments of the gas over bitumen royalty adjustments received by the Corporation under the Natural Gas Royalty Regulation (2002) should the related properties resume production. The expected repayments of the gas over bitumen royalty adjustments are estimated based on the present value of the expected gross overriding royalty on future revenues from the production of proved and probable reserves. Accretion of the provision due to the passage of time and change in estimated cash flows are recognized in net income or loss. Actual repayments, if any, will be charged against the provision as incurred.

i) 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.

Prior to the disposition of WGS LP on April 25, 2012, the Corporation recognized 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.

j) Income tax

Income tax expense comprises current and deferred components. Income tax expense is recognized in net income 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.

k) Income or loss per share amounts

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

Diluted income or loss per share is calculated giving effect to the potential dilution that would occur if outstanding Share Options, Restricted Rights, Performance Share Units, 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, Restricted Rights and Performance Share Units and the if-converted method for potentially issuable common 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.

l) Newly adopted accounting policies

Effective January 1, 2013, Perpetual has adopted the following new standards and amendments as issued by the IASB. Adoption of these new standards and amendments has had no measurement impact on the Corporation's consolidated financial statements. The enhanced disclosure requirements of IFRS 12, IFRS 13, and amended IFRS 7 have been reflected in these consolidated financial statements and notes.

i) IFRS 10, "Consolidated Financial Statements" replaces the guidance in IAS 27 "Consolidated and Separate Financial Statements". The new standard provides a single model to be applied in the control analysis for all investees, eliminating the current risk and rewards approach.

ii) IFRS 11, "Joint Arrangements" replaces the guidance in IAS 31, "Interests in Joint Ventures" and establishes criteria for classification of joint arrangements as either joint operations or joint ventures. The new standard mandates equity-method accounting for joint ventures; these entities no longer have a choice between proportionate consolidation and equity accounting. An entity's interest in a joint operation, where the parties have rights to the assets and obligations for the liabilities, is to be accounted for on the basis of the entity's interest in the assets, liabilities, revenues and expenses of the operation. The relationships are accounted for as joint operations similar to jointly controlled assets or operations under IAS 31.

iii) IFRS 12, "Disclosure of Interest in Other Entities" provides the required disclosures for entities that have interests in subsidiaries or joint arrangements. Disclosure requirements under the new standard aim to provide information that will assist financial statement users in their understanding of the nature, risks, and financial effects of an interest in other entities.

iv) IFRS 13, "Fair Value Measurement" provides a single source of fair value measurement guidance by replacing the guidance contained in other IFRSs. The new standard defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction. IFRS 13 also establishes a framework for measurement of fair value and requires disclosures that allow users to evaluate fair value methodology and the inputs used.

v) IFRS 7, "Financial Instruments: Disclosures" was amended to provide additional guidance on disclosure of financial assets and financial liabilities in the statement of financial position.

m) Recent pronouncements issued

Perpetual will be required to adopt the following applicable new standards and amendments as issued by the IASB. The Corporation is currently evaluating the impact on the consolidated financial statements as discussed below.

i) IFRIC 21, "Levies" provides guidance on accounting for levies in accordance with the requirements of IAS 37, Provisions, Contingent Liabilities and Contingent Assets. The interpretation defines a levy as an outflow from an entity imposed by a government in accordance with legislation and states that levies do not arise from executory contracts or other contractual arrangements. The interpretation also confirms that an entity recognizes a liability for a levy only when the triggering event specified in the legislation occurs. This IFRIC is effective for annual periods commencing on or after January 1, 2014 and is to be applied retrospectively. The Corporation intends to adopt IFRIC 21 in its financial statements for the annual period beginning January 1, 2014.

ii) IFRS 9, "Financial Instruments" establishes principles for the disclosure of financial assets and financial liabilities that will present information that is useful for the assessment of the amounts, timing and uncertainty of an entity's future cash flows. The IFRS is applicable to all items that fall within the scope of IAS 39, "Financial Instruments: Recognition and Measurement". This IFRS is effective for annual periods commencing on or after January 1, 2018 and is to be applied retrospectively. The Corporation intends to adopt IFRS 9 in its financial statements for the annual period beginning January 1, 2018.

Perpetual has not applied any of these new standards as of December 31, 2013. The Corporation is currently evaluating the extent of the impact that adoption will have on the consolidated financial statements.

5. ASSETS HELD FOR SALE

As at		December 31, 2012
Assets held for sale		
Property, plant and equipment (note 7)	$	4,621
Exploration and evaluation (note 8)		17,700
	$	22,321
Liabilities associated with assets held for sale		
Decommissioning obligations (note 13)	$	93

During the first quarter of 2013, the Corporation closed the dispositions of all assets and associated liabilities presented as held for sale at December 31, 2012 for net cash proceeds of $76.8 million resulting in a gain on dispositions of $51.8 million. The dispositions consisted principally of the Elmworth property but also included non-core oil and natural gas properties in the Corporation's West Central CGU.

6. EQUITY-METHOD INVESTMENT

Perpetual's equity-method investment consists of a 30 percent interest in WGS LP which operates a gas storage facility in Alberta, Canada.

Prior to April 25, 2012, WGS LP was a wholly owned subsidiary of Perpetual. On April 25, 2012, Perpetual sold a 90 percent interest in WGS LP for cash proceeds of $80.9 million. As part of the sale Perpetual continues to provide management and operational services to WGS LP for an annual fee. The Corporation also retained an option, exercisable within one year of closing, to buy back from the purchaser up to a 30 percent additional ownership interest in WGS LP at the same price as the initial sale plus working capital and other adjustments, less any dividends paid, for a final ownership interest post any exercise of the buy-back option of up to 40 percent ("WGS Call Option").

On April 25, 2013, Perpetual exercised the WGS Call Option to buy back an additional 20 percent interest in WGS LP for total consideration of $21.4 million comprised of $19.1 million in cash and $2.3 million related to the value of the option. The transaction closed on May 24, 2013 resulting in an increase in Perpetual's total ownership interest to 30 percent. The unexercised portion of the option has expired.

For the year ended December 31, 2013, the Corporation received dividends of $2.4 million (December 31, 2012 - $0.9 million) from WGS LP representing Perpetual's share of total dividends declared. Other transactions between Perpetual and WGS LP during the period totaled $2.0 million (December 31, 2012 - $1.3 million) consisting primarily of revenue earned related to the management services agreement.

Summary financial information for the Corporation's equity-method investment in WGS LP is as follows:

As at	**December 31, 2013**	December 31, 2012
Current assets	**$ 2,925**	$ 1,489
Non-current assets	**119,619**	85,551
Total assets	**122,544**	87,040
Current liabilities	**739**	3,768
Non-current liabilities (1)	**31,596**	48,677
Total liabilities	**32,335**	52,445
Net assets	**90,209**	34,595
Corporation's share of net assets	**27,063**	3,460
Adjustments on acquisition of interest in WGS LP	**1,284**	2,033
Equity-method investment	**$ 28,347**	$ 5,493

(1) Includes long term bank indebtedness of $7.9 million (December 31, 2012 – $3.8 million).

For the period ended	**December 31, 2013**	December 31, 2012
Revenue	**$ 16,864**	$ 10,533
Depreciation	**(3,564)**	(2,398)
Other expenses	**(2,609)**	(4,357)
Unrealized gain (loss) on gas storage obligation derivative	**4,920**	(8,786)
Net income (loss)	**15,611**	(5,008)
Share of net income (loss) of equity-method investment	**$ 3,789**	$ (572)

7. PROPERTY, PLANT AND EQUIPMENT

	Oil and gas properties	Corporate assets	Total
Cost			
December 31, 2011	$ 2,640,472	$ 6,149	$ 2,646,621
Additions	76,136	221	76,357
Change in decommissioning obligations estimates (note 13)	(10,352)	–	(10,352)
Transferred from exploration and evaluation (note 8)	5,346	–	5,346
Acquisitions	1,113	–	1,113
Dispositions	(234,566)	(83)	(234,649)
Reclassification to assets held for sale (note 5)	(4,709)	–	(4,709)
December 31, 2012	2,473,440	6,287	2,479,727
Additions	93,180	120	93,300
Change in decommissioning obligations estimates (note 13)	2,182	–	2,182
Transferred from exploration and evaluation (note 8)	1,426	–	1,426
Acquisitions	808	–	808
Dispositions	(8,952)	–	(8,952)
Reclassification to assets held for sale	(1,581)	–	(1,581)
December 31, 2013	**$ 2,560,503**	**$ 6,407**	**$ 2,566,910**
Accumulated depletion, depreciation and impairment losses			
December 31, 2011	$ (1,813,881)	$ (4,812)	$ (1,818,693)
Depletion and depreciation	(104,964)	(703)	(105,667)
Dispositions	69,239	34	69,273
Impairment losses	(54,313)	–	(54,313)
Reclassification to assets held for sale (note 5)	88	–	88
December 31, 2012	(1,903,831)	(5,481)	(1,909,312)
Depletion and depreciation	(92,380)	(497)	(92,877)
Dispositions	7,062	–	7,062
Impairment reversal	5,171	–	5,171
December 31, 2013	**$ (1,983,978)**	**$ (5,978)**	**$ (1,989,956)**
Carrying amount			
December 31, 2012	$ 569,609	$ 806	$ 570,415
December 31, 2013	**$ 576,525**	**$ 429**	**$ 576,954**

At December 31, 2013, property, plant and equipment included $7.9 million (December 31, 2012 – $7.3 million) of costs currently not subject to depletion and $19.6 million (December 31, 2012 – $19.6 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, 2013, the Corporation disposed of oil and natural gas properties, including those classified as held for sale as at December 31, 2012 (note 5), for cash proceeds of $79.0 million (2012 – $167.2 million). Gains on dispositions totaling $52.1 million (2012 – $49.0 million) were recorded in net income.

For the year ended December 31, 2013, the Corporation reversed a previous year impairment charge of $5.2 million on natural gas assets geographically located within the West Central CGU. The impairment was reversed as a result of positive reserve revisions related to the strong economic performance of Perpetual's wells in West Central.

For the year ended December 31, 2012, the Corporation recognized impairment losses of $54.3 million on natural gas assets geographically located within the Birchwavy West, Birchwavy East, and Other South CGUs. Impairments realized were a result of a decline in forecasted 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 pre-tax discount rates between 10.0 and 15.0 percent. The amount of 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.

8. EXPLORATION AND EVALUATION

	2013	2012
Balance, beginning of year	**$ 80,494**	$ 106,763
Additions	**5,617**	4,765
Acquisitions	**7,400**	1,294
Dispositions	**–**	(3,524)
Transferred to property, plant and equipment	**(1,426)**	(5,346)
Non-cash exploration and evaluation expense	**(2,715)**	(5,758)
Reclassification to assets held for sale	**(1,193)**	(17,700)
Balance, end of year	**$ 88,177**	$ 80,494

During the year ended December 31, 2013, $4.5 million (2012 – $3.5 million) in costs were charged directly to E&E expense in net loss.

9. LONG TERM CROWN RECEIVABLE (restated note 2)

Perpetual is entitled to gas over bitumen royalty adjustments from the government (the Alberta "Crown") with respect to foregone production from gas wells that have been shut-in where they are deemed to be in communication with potentially recoverable bitumen. For operated facilities, the royalty adjustments are received by the Corporation as a reduction to the Corporation's Crown royalties payable. For non-operated facilities, Perpetual receives cash payments from joint venture partners. As at December 31, 2013, Perpetual had accumulated royalty adjustments on operated facilities in excess of the Corporation's accumulated Crown royalties payable totaling $18.1 million (December 31, 2012 - $17.7 million). Of this amount, $7.1 million (December 31, 2012 – $8.9 million) is included in current accounts receivable as the Corporation expects to recover this amount against Crown royalties otherwise payable in the next twelve months. The remaining $11.0 million (December 31, 2012 - $8.8 million) is recorded as long term Crown receivable as the Corporation expects to recover the amounts against Crown royalties payable over a period of time beyond the next year.

10. BANK INDEBTEDNESS

The Corporation's credit facility is with a syndicate of Canadian chartered banks. On April 26, 2013, the Corporation's lenders completed their semi-annual review of the borrowing base under the credit facility. The total availability under the facility was reduced to $125 million from $127.5 million which consists of a demand loan of $95 million; a working capital facility of $15 million, and a $15 million acquisition facility. Total availability under the facility was further reduced to $110 million with the maturity of the acquisition facility on July 31, 2013. On October 31, 2013, the Corporation's lenders completed their semi-annual review of the borrowing base under the credit facility and total availability was confirmed at $110 million. The revolving feature of the credit facility has been extended to October 30, 2014. The next semi-annual redetermination of the Corporation's borrowing base will occur on or before April 30, 2014.

The Corporation has covenants that require twelve month trailing income 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 lender's covenants at December 31, 2013. In addition to amounts outstanding under the credit facility, the Corporation has outstanding letters of credit in the amount of $5.9 million (December 31, 2012 – $7.6 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, 2013 was 5.5 percent (December 31, 2012 – 5.5 percent).

11. 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, 2013. 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. At December 31, 2013, the senior notes are presented net of $2.3 million in issue costs which are amortized using an effective interest rate of 9.1 percent.

12. CONVERTIBLE DEBENTURES

The Corporation's 6.50% convertible unsecured subordinated debentures ("6.50% Convertible Debentures") issued on June 20, 2007 and traded on the Toronto Stock Exchange ("TSX") under the symbol PMT.DB.C matured on June 30, 2012. They yielded interest at 6.50 percent per annum paid semi-annually on June 30 and December 31 of each year and were subordinated to substantially all other liabilities of the Corporation including the credit facility and senior notes. The 6.50% Convertible Debentures were 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 6.50% Convertible Debentures were paid out in cash on June 30, 2012 at maturity.

The Corporation's 7.25% Convertible Debentures amended on December 17, 2009, which trade under the symbol PMT.DB.D, mature on January 31, 2015, bear interest at 7.25 percent 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% Convertible Debentures issued on May 26, 2010, which trade under the symbol PMT.DB.E, mature on December 31, 2015, bear interest at 7.00 percent 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.

Series	6.50%	7.25%	7.00%	Total
Trading symbol (TSX)	**PMT.DB.C**	**PMT.DB.D**	**PMT.DB.E**	
Carrying amount				
Balance, December 31, 2011	$ 74,250	$ 95,325	$ 53,695	$ 223,270
Accretion	316	890	892	2,098
Amortization of debenture issue fees	359	453	418	1,230
Repayment of principal on maturity	(74,925)	–	–	(74,925)
Balance, December 31, 2012	–	96,668	55,005	$ 151,673
Accretion	–	1,015	996	2,011
Amortization of debenture issue fees	–	493	500	993
Redemptions	–	(68)	(113)	(181)
Balance, December 31, 2013	**$ –**	**$ 98,108**	**$ 56,388**	**$ 154,496**
Market value				
December 31, 2012	$ –	$ 94,723	$ 56,400	$ 151,123
December 31, 2013	**$ –**	**$ 97,903**	**$ 57,333**	**$ 155,236**
Principal amount outstanding				
December 31, 2012	$ –	$ 99,972	$ 60,000	$ 159,972
December 31, 2013	**$ –**	**$ 99,901**	**$ 59,878**	**$ 159,779**

13. PROVISIONS

A reconciliation of provisions is provided below:

	Gas over bitumen obligations		Decommissioning obligations	
	2013	2012	**2013**	2012
		Restated (note 2)		
Balance, beginning of year	**$ 2,737**	$ 3,356	**$ 206,379**	$ 242,860
Obligations acquired	**–**	–	**73**	45
Obligations incurred	**–**	–	**3,392**	1,308
Obligations disposed	**–**	–	**(62)**	(30,377)
Change in risk free rate	**–**	–	**(12,574)**	9,569
Change in estimates	**211**	(619)	**14,756**	(19,921)
Obligations settled	**–**	–	**(2,497)**	(1,825)
Accretion	**–**	–	**4,439**	4,813
Reclassification to liabilities associated with assets held for sale (note 5)	**–**	–	**–**	(93)
Balance, end of year	**$ 2,948**	$ 2,737	**$ 213,906**	$ 206,379

a) Decommissioning obligations

The total future 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.

At December 31, 2013, the Corporation estimated the net present value of its total decommissioning obligations to be $213.9 million (December 31, 2012 – $206.4 million) based on an undiscounted total future liability of $236.8 (December 31, 2012 – $260.6 million). These payments are expected to be made over the next 25 years with the majority of costs incurred between 2020 and 2030. At December 31, 2013, the Corporation used a weighted average risk free rate of 2.41 percent (December 31, 2012 – 2.24 percent) to calculate the present value of the decommissioning obligation provisions.

b) Gas over bitumen obligation (restated note 2)

The gas over bitumen obligation represents the present value of expected repayments of the gas over bitumen royalty adjustments received or receivable by the Corporation under the Natural Gas Royalty Regulation (2002) in the event the shut-in gas over bitumen assets resume production. The cash flows are based on the estimated timing of future revenues and the related over-riding royalties that will be incurred in future periods. At December 31, 2013, the Corporation estimated the net present value of its total gas over bitumen obligation to be $2.9 million (December 31, 2012 - $2.7 million) based on undiscounted total future repayments of $10.8 million (December 31, 2012 - $11.6 million). The majority of these repayments are expected to occur between 2020 and 2032. At December 31, 2013, the Corporation used a liability specific discount rate of 15.0 percent (December 31, 2012 – 15.0 percent) to calculate the present value of the provision.

14. SHARE CAPITAL

a) Authorized

Authorized capital consists of an unlimited number of common shares.

b) Issued and outstanding

A reconciliation of share capital is provided below:

		2013		2012
	Shares	**Amount**	Shares	Amount
Balance, beginning of year	**147,455,167**	**$ 1,255,450**	146,966,260	$ 1,254,273
Common shares issued pursuant to:				
- Restricted Rights Plan	**894,553**	**1,501**	488,907	1,177
- Performance Share Units Plan	**90,349**	**334**	–	–
- Share Option Plan	**50,318**	**30**	–	–
Balance, end of year	**148,490,387**	**$ 1,257,315**	147,455,167	$ 1,255,450

c) Per share information

	Year ended December 31,	
	2013	2012
(thousands, except per share amounts)		
Net income (loss) – basic	**$ 7,620**	$ (75,986)
Effect of dilutive securities	**–**	–
Net income (loss) – diluted	**$ 7,620**	$ (75,986)
Weighted average common shares outstanding – basic	**148,144**	147,085
Effective of dilutive securities	**2,098**	–
Weighted average common shares outstanding – diluted	**150,242**	147,085
Income (loss) per share - basic and diluted	**$ 0.05**	$ (0.52)

In computing per share amounts for the year ended December 31, 2012, 7,045,250 Share Options, 2,245,737 Restricted Rights, 1,328,360 Performance Share Rights, and 21,901,026 potentially issuable common shares through the convertible debentures were excluded as the Corporation had a net loss.

15. SHARE BASED PAYMENTS

a) Share Option Plan

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 granted 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 grant.

Participants in 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. The Corporation has the right to accept or refuse such offers. For the year ended December 31, 2013, the Corporation recorded $1.8 million in share based payment expense related to Share Options (2012 – $2.7 million).

At December 31, 2013, the Corporation had 12.5 million Share Options and Restricted Rights (December 31, 2012 – 11.4 million) issued and outstanding relative to the 14.8 million (ten percent of total common shares outstanding) reserved under the Share Option and Restricted Rights Plans (December 31, 2012 – 14.7 million). As at December 31, 2013, 3.4 million Share Options granted under the Share Option Plan had vested but were unexercised (December 31, 2012 – 0.8 million).

The Corporation used the trinomial option pricing model to calculate the estimated fair value of the outstanding Share Options. During the year ended December 31, 2013, the Corporation granted 2.7 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	2013	2012
Dividend yield (%)	**0.0**	0.0
Forfeiture rate (%)	**12.0**	8.0 – 12.0
Expected volatility (%)	**48.0 – 52.1**	44.1 – 50.8
Risk-free interest rate (%)	**1.1 – 1.6**	1.0 – 1.5
Expected life (years)	**2.5 – 3.5**	2.5 – 3.5
Vesting period (years)	**3.0**	3.0
Contractual life (years)	**4.0**	4.0
Weighted average grant date fair value	**$ 0.38**	$ 0.30

		2013		2012
	Average exercise price	**Share options**	Average exercise price	Share options
Balance, beginning of year	**$ 1.32**	**9,177,175**	$ 4.00	12,297,100
Granted	**1.12**	**2,665,000**	0.96	7,045,250
Exercised	**0.69**	**(104,439)**	4.55	(4,512,875)
Forfeited	**6.34**	**(170,500)**	4.12	(5,652,300)
Cancelled	**1.51**	**(366,209)**	–	–
Balance, end of year	**$ 1.20**	**11,201,027**	$ 1.32	9,177,175

The following table summarizes information about Share Options outstanding at December 31, 2013:

	Options Outstanding			**Options Exercisable**	
Range of exercise prices	Number of share options	Average contractual life (years)	Weighted average exercise price	Number of share options	Weighted average exercise price
$0.62 to $0.83	1,213,279	2.29	$ 0.62	348,484	$ 0.62
$0.84 to $1.07	5,085,448	2.56	1.03	1,682,556	1.03
$1.08 to $1.15	2,445,000	3.64	1.11	–	–
$1.16 to $5.03	2,457,300	2.23	1.92	1,365,701	1.99
Total	**11,201,027**	**2.70**	**$ 1.20**	**3,396,741**	**$ 1.38**

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, 2013, $0.6 million in share based payment expense was recorded in respect of Restricted Rights (2012 – $1.5 million).

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

	2013	2012
Balance, beginning of year	**2,245,737**	1,365,107
Granted	**200,432**	1,782,250
Exercised	**(988,028)**	(491,307)
Forfeited	**(127,058)**	(410,313)
Cancelled	**(20,510)**	–
Balance, end of year	**1,310,573**	2,245,737

c) Performance Share Rights Plan

The Corporation has a Performance Share Rights Plan for the Corporation's senior management team. Performance Share Rights granted under the Performance Share Rights Plan vest two years after the date upon which the Performance Share Rights were granted. The Performance Share Rights that vest and become redeemable are a multiple of the Performance Share Rights granted dependent 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, 2013, the Corporation had 2,298,500 Performance Share Rights issued and outstanding under the Performance Share Rights Plan (December 31, 2012 – 1,328,360).

For the year ended December 31, 2013, $1.2 million in share based payment expense was recorded in respect of the Performance Share Rights granted (2012 – $0.3 million).

d) Compensation awards

The Corporation has agreements in place with certain employees whereby over a period of three years they may be entitled to receive shares of the Corporation purchased on the open market by an independent trustee if they remain employees of Perpetual during such time. This does not dilute equity or involve the issuance of shares from treasury.

At December 31, 2013, the Corporation had 1,212,000 of these awards and issued and outstanding (2012 – nil).

For the year ended December 31, 2013, $0.1 million in share based payment expense was recorded in respect of the awards (2012 – nil).

The Corporation also has agreements in place with directors and certain employees whereby, in the case of directors, upon retirement from the Board of Directors, or in the case of employees, over a period of two years if they remain employees of Perpetual during such time, may be entitled to receive, at the discretion of the Board, cash, a grant of restricted rights or shares of the Corporation purchased on the open market by an independent trustee.

At December 31, 2013, the Corporation had 1,810,000 of these awards issued and outstanding (2012 – nil).

For the year ended December 31, 2013, $0.3 million in share based payment expense was recorded in respect of the compensation awards granted (2012 – nil).

As at December 31, 2013, no shares have been purchased for the purpose of these agreements by the independent trustee (2012 – nil).

16. FINANCE EXPENSE

The components of finance expense are as follows:

	Year ended December 31	
	2013	2012
Interest	**$ (32,482)**	$ (36,354)
Accretion on decommissioning obligations (note 13)	**(4,439)**	(4,813)
(Loss) gain on marketable securities	**(92)**	801
(Loss) gain on call option	**(1,274)**	47
Change in estimate on gas over bitumen obligation (note 13)	**(211)**	619
Gain on retained investment in former subsidiary	**–**	2,104
Gain on gas storage obligation derivative	**–**	3,636
Finance expenses recognized in net income or loss	**$ (38,498)**	$ (33,960)

17. NON-CASH WORKING CAPITAL INFORMATION

	Year ended December 31,	
	2013	2012
Accounts receivable	**$ (2,312)**	$ (1,742)
Prepaid expenses and deposits	**1,559**	883
Accounts payable and accrued liabilities	**(2,267)**	(5,797)
Change in non-cash working capital (1)	**$ (3,020)**	$ (6,656)

(1) Includes working capital balances sold as part of the 2012 disposition of the Corporation's controlling interest in WGS LP.

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

	Year ended December 31,	
	2013	2012
Operating	**$ (146)**	$ 1,162
Financing	**(20)**	33
Investing	**(2,854)**	(7,851)
Change in non-cash working capital (1)	**$ (3,020)**	$ (6,656)

(1) Includes working capital balances sold as part of the 2012 disposition of the Corporation's controlling interest in WGS LP.

18. 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, 2013, 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, 2013 is $0.6 million (December 31, 2012 – $0.8 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 $1.7 million as at December 31, 2013 (December 31, 2012 – $2.8 million).

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 anticipates that cash flows including cash flow from operating activities, proceeds from closed and potential future asset dispositions and available funds from the Corporation's credit facility will provide the required funds to discharge the Corporation's obligations, carry out exploration and development programs and fund ongoing operations for the foreseeable future.

The following are the contractual maturities of financial liabilities and associated interest payments as at December 31, 2013:

Contractual repayments of financial liabilities	**Total**	2014	2015	2016-2018
Accounts payable and accrued liabilities	**$ 45,048**	$ 45,048	$ –	$ –
Derivatives	**9,246**	6,468	2,778	–
Bank indebtedness – principal (1)	**70,618**	70,618	–	–
Senior notes – principal	**150,000**	–	–	150,000
Convertible debentures (2)	**159,779**	–	159,779	–
Total	**$ 434,691**	$ 122,134	$ 162,557	$ 150,000

(1) The revolving feature of the credit facility expires on October 30, 2014 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 day.

(2) Assuming repayment of principal 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 income 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 foreign 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.

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 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 derivatives and fixed-price physical delivery sales contracts.

The Corporation's policies as they relate to hedging and risk management are as follows:

Restrictive Policy	**Contract Type**	**Hedging Limit**
Internal Hedging and Risk Management Policy (1)	Financial or forward physical oil or natural gas liquids-based hedge volumes	80 percent of the average forecast future oil and natural gas liquids production volume after royalties
Internal Hedging and Risk Management Policy (1)	Financial or forward physical natural gas-based hedge volumes	80 percent of the average forecast future natural gas production volumes after royalties plus 40 percent of the forecast future gas over bitumen deemed production volumes
Credit facility agreement	Financial or forward physical oil, condensate, or natural gas-based hedge volumes	60 percent of the trailing quarter's production including gas over bitumen deemed production

(1) For the purposes of these limitations, basis and differential volumes are counted at 25 percent and unexercised call or put options are counted at 50 percent of the contract volumes.

As at December 31, 2013, 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 income for the year ended December 31, 2013 were $6.3 million (2012 – $29.0 million). The realized gains on commodity price derivatives for the year ended December 31, 2013, included $0.9 million in respect of settlement of contracts prior to maturity (2012 – $2.1 million).

Natural gas contracts

At December 31, 2013, the Corporation had entered into financial and forward natural gas sales arrangements at AECO as follows:

Type of contract	Perpetual Sold/Bought	Volumes at AECO (GJ/d)	Price ($/GJ)	Term
Financial	sold	40,000	3.60	January 2014
Financial	bought	(10,000)	3.66	January 2014
Physical	sold	25,000	3.74	January 2014
Physical	bought	(10,000)	3.66	January 2014
Financial	sold	10,000	3.71	January 2014 – December 2014

At December 31, 2013, the Corporation had entered into the following financial call option gas sales arrangements, whereby the Corporation's counterparty has the right to settle the specified volumes of natural gas at the specified prices in the future periods. Any subsequent changes in the fair values of the call options will be included in change in fair values of commodity derivatives in net income or loss.

Type of contract	Perpetual Sold/Bought	Volumes at AECO (GJ/d)	Price ($/GJ)	Term
Financial	sold	10,000	4.25	January 2014 – December 2014

At December 31, 2013, the Corporation had entered into financial natural gas sales arrangements to fix the basis differential between the New York Mercantile Exchange ("NYMEX") and AECO trading hubs. The price at which these contract settles is equal to the NYMEX index less a fixed basis amount.

Type of contract	Perpetual Sold/Bought	Volumes at NYMEX-AECO (MMBtu/d)	Price ($US/MMBtu)	Term
Financial	sold	2,500	(0.42)	January 2014 – March 2014
Financial	bought	(2,500)	(0.48)	January 2014 – March 2014
Financial	sold	10,000	(0.51)	April 2014 – October 2014

At December 31, 2013, the Corporation had entered into the following financial natural gas sales arrangements at NYMEX as follows:

Type of contract	Perpetual Sold/Bought	Volumes at NYMEX (MMBtu/d)	Price ($US/MMBtu)	Term
Financial	sold	20,000	4.48	February 2014 – March 2014
Financial	bought	(5,000)	4.39	February 2014 – March 2014
Financial	sold	2,500	4.25	April 2014 – October 2014
Financial	bought	(2,500)	4.16	April 2014 – October 2014

Oil contracts

At December 31, 2013, the Corporation had entered into financial and forward physical oil sales arrangements to fix the basis differential between the West Texas Intermediate ("WTI") and Western Canadian Select ("WCS") trading hubs. The price at which this contract settles is equal to the WTI index less a fixed basis amount.

At December 31, 2013 the Corporation had entered into the following costless collar oil sales arrangements:

Type of contract	Volumes at WTI (bbl/d)	Floor price ($US/bbl)	Ceiling price ($US/bbl)	Term
Collar (1)	500	90.00	103.15	January 2014 – December 2014
Collar	500	85.00	91.10	January 2014 – December 2014
Collar	500	85.00	91.20	January 2014 – December 2014
Collar	500	87.50	95.25	January 2015 – December 2015
Collar	500	87.50	95.75	January 2015 – December 2015

(1) In this collar arrangement Perpetual received a ceiling price above the market price for such collars, and in exchange should the WTI index settle above $US103.15 per bbl in any month during the contract period Perpetual will receive a price of $US93.00 per bbl.

At December 31, 2013, the Corporation has entered into the following fixed price oil sales arrangements:

Type of contract	Perpetual Sold/Bought	Volumes at WTI (bbl/d)	Price ($US/bbl)	Term
Financial	sold	1,000	90.00	January 2014 – December 2014

At December 31, 2013, the Corporation had entered into the following 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 income or loss.

Type of contract	Perpetual Sold/Bought	Volumes at WTI (bbl/d)	Price ($US/bbl)	Term
Financial (1)	sold	2,000	105.00	January 2014 – December 2014
Financial	sold	1,500	100.00	January 2015 – December 2015

(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.

Foreign exchange contracts

At December 31, 2013, the Corporation had entered into the following $US forward sales arrangement:

Type of contract	Perpetual Sold/Bought	Notional $US/month	Exchange rate (Cdn$/$US)	Term
Financial (1)	sold	1,000,000	1.1000	January 2014 – June 2015

(1) The Corporation receives $1,000 each day during the month that the daily exchange rate is between $1.0000 and $1.1000. If the average monthly exchange rate is greater than $1.1000 the Corporation pays $US1,000,000 multiplied by the difference between the average monthly exchange rate and $1.1000. No settlement occurs between the Corporation and the counterparty if the average monthly exchange rate settles below $1.0000.

At December 31, 2013, the Corporation had entered into the following $US forward sales arrangement:

Type of contract	Perpetual Sold/Bought	Notional floor $US/month	Notional ceiling $US/month	Exchange rate floor (Cdn$/$US)	Exchange rate ceiling (Cdn$/$US)	Term
Financial (1)	sold	2,500,000	5,000,000	1.0400	1.1410	July 2014 – December 2015

(1) If the average monthly exchange rate is greater than $1.1410 the Corporation pays $US5,000,000 multiplied by the difference between the average monthly exchange rate and $1.1000. If the monthly average exchange rate settles below $1.0400 the Corporation receives $US2,500,000 multiplied by the difference between the average monthly exchange rate and $1.0400.

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

	Year ended December 31, 2013	2012
Realized loss on financial oil contracts	**$ (2,596)**	$ (2,613)
Realized gain on financial natural gas contracts	**8,266**	30,051
Realized gain on forward foreign exchange contracts	**605**	1,597
Unrealized gain on financial oil contracts	**5,411**	10,507
Unrealized loss on physical oil contracts	**(519)**	–
Unrealized loss on financial natural gas contracts	**(2,447)**	(11,896)
Unrealized gain on physical natural gas contracts	**64**	–
Unrealized loss on forward foreign exchange contracts	**(726)**	(204)
Unrealized gain on power derivatives	**–**	(631)
Change in fair value of commodity price derivatives	**$ 8,058**	$ 26,811

Natural gas sensitivity analysis

As at December 31, 2013, if future natural gas prices changed by $0.25 per GJ with all other variables held constant, the fair value of commodity price derivatives and after tax net income for the period would change by $1.7 million. Fair value sensitivity was based on published forward AECO and NYMEX prices.

Oil sensitivity analysis

As at December 31, 2013, if future oil prices changed by $5.00 per boe with all other variables held constant, the fair value of commodity price derivative and after tax net income for the period would have changed by $0.6 million. Fair value sensitivity was based on published forward WTI and WCS prices.

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 income or loss, thereby potentially affecting the Corporation's capital investments.

The Corporation's senior notes and convertible debentures were issued at a fixed interest rate and as such these securities are not materially impacted by market interest rate fluctuations. To ensure accounts payable and accrued liabilities 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, 2013 (December 31, 2012 – nil).

Interest rate sensitivity analysis

For the year ended December 31, 2013, if interest rates changed by one percent with all other variables held constant, the impact on interest expense and net income would be $0.7 million.

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

Perpetual fair value measurements are classified as one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forward prices for commodities.

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

The Corporation aims to maximize the use of highly observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation.

The fair value of accounts receivable, accounts payable and accrued liabilities approximate their carrying amounts due to their short terms to maturity. The fair value of the long term Crown receivable approximates the carrying value as the Corporation expects to recover the full carrying amount by way of future gas Crown royalties. Bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying amount. The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchy levels:

				Fair value	
As at December 31, 2013	**Gross**	**Netting [1]**	**Carrying amount**	**Level 1**	**Level 2**
Financial assets					
Fair value through profit and loss					
Derivatives – current	**596**	**(270)**	**326**	**–**	**326**
Derivatives – non-current	**19**	**–**	**19**	**–**	**19**
Financial liabilities					
Financial liabilities at amortized cost					
Senior notes	**147,719**	**–**	**147,719**	**–**	**144,750**
Convertible debentures	**154,496**	**–**	**154,496**	**155,236**	**–**
Fair value through profit and loss					
Derivatives – current	**6,738**	**(270)**	**6,468**	**–**	**6,468**
Derivatives – non-current	**2,778**	**–**	**2,778**	**–**	**2,778**

(1) Derivative assets and liabilities presented in the statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides or the legal right and intention for net settlement exists.

As at December 31, 2012	Gross	Netting [1]	Carrying amount	Fair value Level 1	Fair value Level 2
Financial assets					
Fair value through profit and loss					
Marketable securities	1,963	–	1,963	1,963	–
Derivatives – current	9,144	(5,441)	3,703	–	3,703
Financial liabilities					
Financial liabilities at amortized cost					
Senior notes	147,177	–	147,177	–	144,000
Convertible debentures	151,673	–	151,673	151,123	–
Fair value through profit and loss					
Derivatives – current	6,893	(5,441)	1,452	–	1,452
Derivatives – non-current	8,402	–	8,402	–	8,402

(1) Derivative assets and liabilities presented in the statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides or the legal right and intention for net settlement exists.

19. 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 of 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 cash flow from operations. As at December 31, 2013, the Corporation's ratio of net debt to operating cash flow was 7.2 to 1 (December 31, 2012 – 8.0 to 1) reflecting changes in net debt and cash flow from operations. This ratio is monitored continuously by the Corporation, and the targeted range of net debt to cash flow varies based on such factors as acquisitions or dispositions, 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 7.25% Convertible Debentures and 7.00% Convertible Debentures mature on January 31, 2015 and December 31, 2015 respectively. While the Corporation has the option to settle all or a portion of the outstanding 7.25% Convertible Debentures and 7.00% Convertible Debentures through the issuance of shares by giving notice of such intent to debenture holders not more than 60 and not less than 30 days prior to the maturity date, it is the intention of the Corporation to settle in cash. The banks for the Corporation's revolving credit facility are awaiting more certainty on the Corporation's plans to settle the debenture prior to extending the revolving credit facility which, if not renewed, comes due on October 31, 2013. The Corporation will apply to have the facility renewed prior to the next semi-annual review on April 30, 2014. In advance of the facility coming due, management plans include pursing alternative financing arrangements on the facility based on the Corporation's increased year-over-year externally evaluated reserve values.

Management is pursuing repayment options for the 7.25% Convertible Debentures and 7.00% Convertible Debentures including asset dispositions, refinancing, or a combination thereof. There is no assurance that the Corporation will be able raise additional capital to settle all or a portion of the outstanding 7.25% Convertible Debentures and 7.00% Convertible Debentures in cash, in which case, the Corporation would have the option to settle all or a portion of the debentures.

20. COMMITMENTS

Perpetual has contractual agreements comprised of office lease costs and related sublease recoveries, as well as long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada. As of December 31, 2013, the future minimum payments under these contractual agreements consisted of:

	Pipeline commitments	Operating lease commitments
2014	$ 4,599	$ 1,743
2015	1,682	1,678
2016	94	1,661
2017	34	1,598
2018	24	399
Total	**$ 6,433**	**$ 7,079**

21. 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:

	Year ended December 31,	
	2013	2012
Loss before income tax, including non-controlling interests	**$ 7,620**	$ (79,739)
Combined federal and provincial tax rate (%)	**25.0**	25.0
Computed income tax benefit	**1,905**	(19,935)
Increase (decrease) in income taxes resulting from:		
Non-deductible expenses	**994**	1,230
Non-taxable capital gain	**–**	(7,760)
Expired tax pools	**–**	10,793
Unrecognized tax asset	**(2,421)**	9,700
Other	**(478)**	2,219
Deferred income taxes	**$ –**	$ (3,753)

Income tax rates remained at 25.0 percent in 2013 and 2012 with no changes to federal statutory income tax rates.

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

	Year ended December 31,	
	2013	2012
Property, plant and equipment	**$ 28,539**	$ 44,018
Other	**6,287**	3,303
Gas over bitumen royalty obligation	**(737)**	(684)
Decommissioning obligations	**(34,089)**	(46,637)
	$ –	$ –

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

	Year ended December 31,	
	2013	2012
Non-capital losses	**$ 146,703**	$ 232,025
Capital losses	**160,969**	159,224
Decommissioning obligation	**77,551**	19,923
Other	**11,055**	–
	$ 396,278	$ 411,172

The tax losses expire between 2014 and 2032. The deductible temporary differences do not expire under current tax legislation. Deferred tax assets have not been recognized in respect of these temporary differences 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 $551 million (December 31, 2012 – $490 million) available for future use as deductions from taxable income.

22. 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:

	Year ended December 31,	
	2013	2012
Short-term fees and other short-term benefits	**$ 3,860**	$ 3,630
Share based compensation expense	**1,869**	2,001
	$ 5,729	$ 5,631

23. 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.

	Year ended December 31,	
	2013	2012
Production and operating	**$ 9,279**	$ 10,107
General and administrative	**24,171**	25,564
	$ 33,450	$ 35,671

During the year ended December 31, 2013, total employee compensation costs included share based payment expense of $4.0 million (2012 – $4.3 million) with the remainder being short-term fees and other short-term benefits.

FORWARD-LOOKING INFORMATION

Certain information regarding Perpetual in this report including management's assessment of future plans and operations and including the information contained under the heading "Outlook" may constitute forward-looking statements under applicable securities laws. The forward-looking information includes, without limitation, statements regarding capital expenditure levels for 2014, prospective drilling activities; forecast production, production type, operations, funds flows, and timing thereof; forecast and realized commodity prices; expected funding, allocation and timing of capital expenditures; projected use of funds flow and anticipated funds flow; planned drilling and development and the results thereof; expected dispositions, anticipated proceeds therefrom and the use of proceeds therefrom; and commodity prices. 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's Annual Information Form and MD&A for the year ended December 31, 2013 and those included in other 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 released 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 10 of this report.

DIRECTORS

Clayton H. Riddell
Executive Chairman

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

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

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

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

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

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

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

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

OFFICERS

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

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

Vicki L. Benoit
Vice President, Production Operations

Jeffrey R. Green
Vice President, Corporate and Engineering Services

Gary C. Jackson
Vice President, Land and Acquisitions

Linda L. McKean
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STOCK EXCHANGE LISTING | TSX | PMT

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

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

Computershare Trust Company of Canada

SHAREHOLDERS ARE

CORDIALLY INVITED TO

ATTEND THE

ANNUAL MEETING

TO BE HELD

MAY 21, 2014

9:00 A.M. (MDT)

CALGARY

PETROLEUM CLUB

319 – 5 AVENUE SW

CALGARY, ALBERTA

CANADA

PERPETUAL
ENERGY

STOCK EXCHANGE LISTING | TSX | **PMT**

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