2014 ANNUAL RESULTS

PERPETUAL
ENERGY

SHAREHOLDERS ARE

CORDIALLY INVITED TO

ATTEND THE

ANNUAL MEETING

TO BE HELD

MAY 20, 2015

9:00 A.M. (MDT)

CALGARY

PETROLEUM CLUB

319 – 5 AVENUE SW

CALGARY, ALBERTA

CANADA

2014 STRATEGIC PRIORITIES

Perpetual focused on five key strategic priorities in 2014:

1. Reduce debt and manage downside risks;
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.

Significant progress was made with respect to these priorities as outlined below.

Reduce debt and manage downside risk

- A focus on debt reduction was successfully reflected in a 12 percent ($45.2 million) decrease in net debt to $331.7 million at December 31, 2014.
- Property dispositions and the execution of the East Edson royalty transaction ("East Edson JV") generated net proceeds of $71.4 million including $47.0 million under the East Edson JV on the disposition of an overriding royalty interest; $21.4 million on the disposition of non-core Mannville heavy oil assets and $3.0 million received on the sale of undeveloped land. Offsetting property dispositions were acquisitions of $1.0 million, primarily related to additional land purchases in the Greater Edson area.
- The East Edson JV also secured funding of an additional $70 million in exploration and development expenditures to kick start full scale development of the Wilrich formation at East Edson, $69 million of which was spent prior to year-end.
- Perpetual also closed two transactions in 2014 which effectively monetized the majority of its future gas over bitumen ("GOB") royalty credits associated with certain shut-in properties in northeast Alberta for net proceeds of $21.3 million.
- Perpetual issued $125 million in 8.75 percent senior notes with the proceeds utilized for the early redemption of $100 million of 7.25 percent Convertible Debentures ("PMT.DB.D") in August 2014 and $25 million of 7.00 percent Convertible Debentures ("PMT.DB.E") on December 31, 2014. The issuance of senior notes and the early redemption of convertible debentures further enhanced Perpetual's financial flexibility by extending the term for a larger percentage of Perpetual's debt into 2019.
- Commodity price management contracts were put in place and actively administered for both oil and gas to protect against downside commodity price risk. Strong realized natural gas prices in the first and second quarters of 2014 were followed by gas price declines later in the year as gas storage levels re-built quickly due to mild summer weather coupled with year over year supply growth. Perpetual realized losses of $5.0 million on gas price hedging contracts during 2014. Average oil and natural gas liquids ("NGL" or "liquids") prices, including derivatives, of $71.82/bbl increased eight percent in 2014 due to strong WTI prices during the first half of 2014 which, along with a narrowing of Western Canadian Select ("WCS") differentials, offset the effect of oil and NGL price declines in the fourth quarter. Perpetual's realized oil and NGL price, including derivatives, was four percent lower than the price before derivatives in 2014, primarily due to hedging losses recorded on financial WTI price contracts during the first three quarters of 2014, which were not fully overcome by gains realized during the fourth quarter of 2014 as oil prices declined.
- On November 5, 2014, Perpetual's borrowing base increased to $105 million as a result of reserve additions driven by drilling activities at East Edson, despite adjustments related to the monetization of additional GOB royalty credits and the disposition of non-core heavy oil properties. On March 5, 2015, the Corporation's lenders agreed to revise financial covenants based on prevailing low commodity prices at the end of 2014 and uncertainty surrounding forecast commodity prices into 2016. Based on internal 2015 and 2016 financial and operating forecasts, Perpetual expects to be in compliance with the lender's new covenants.

Grow Edson liquids-rich gas production, reserves, cash flow, inventory and value

- Capital spending of $81.1 million in 2014 was allocated to liquids-rich natural gas development activities in the Corporation's greater Edson area in the West Central Alberta deep basin.
- On July 16, 2014, Perpetual entered into the East Edson JV to accelerate the development of the Corporation's East Edson property. The arrangement included the disposition of a 50 percent royalty interest in current developed producing reserves in the East Edson area (the "Producing Royalty") for a net $47 million after post-closing adjustments. In addition, the joint venture partner contributed $70 million for the drilling, completion and tie-in of approximately 14 horizontal wells in the Wilrich formation pursuant to a farm-in agreement to earn a second royalty (the "Drilling Royalty"). In combination, the Drilling and Producing Royalties entitle the joint venture partner to receive, on a priority basis, 5.6 MMcf/d of natural gas from the East Edson property plus oil and associated NGL from July 1, 2014 to December 31, 2022 and declining thereafter at 10 percent per year until the Drilling Royalty and the Producing Royalty terminate on December 31, 2034.
- Pursuant to the East Edson JV, Perpetual committed to spend $30 million of the proceeds from the sale of the Producing Royalty to drill, complete and tie-in approximately five additional wells prior to December 31, 2015, substantially following the spending of the $70 million commitment by the partner. The majority of the partner's $70 million commitment and a portion of Perpetual's first $30 million commitment were spent by the end of 2014, with the balance expected to be fully expended by the end of the first quarter of 2015.
- Further to this, Perpetual committed to construct a new gas plant at East Edson to add 30 MMcf/d of processing capacity at an estimated cost of $30 million. Spending on site preparation and equipment purchases for the gas plant began in 2014 with start-up planned for the third quarter of 2015.
- Drilling activities in 2014 included 11 (5.5 net) operated wells and two (0.1 net) non-operated wells drilled in West Edson and 15 (15.0 net) wells drilled in East Edson, including 13 (13.0 net) wells financed from the partner's escrow account.
- Development activities also included expansion of the West Edson facility to 60 MMcf/d gross (30 MMcf/d net).
- Greater Edson production grew 57 percent in 2014 to average 7,649 boe/d (2013 – 4,861 boe/d).
- Proved and probable reserves of 105.5 MMboe were recorded by the Company's independent reserves evaluator McDaniel and Associates Consultants Ltd. ("McDaniel"), up 43.1 MMboe (69 percent) from year-end 2013.

Maximize value of Mannville heavy oil

- Exploration and development spending of $24.6 million at Mannville included the drilling and completion of 20 (17.8 net) horizontal heavy oil wells. The drilling program resulted in three new heavy oil pool discoveries.
- The waterflood pilot initiated in the Mannville I2I pool was expanded and pressure maintenance through waterflood was initiated on two additional pools with seven wells converted to waterflood injection wells in 2014. Additionally, expansion of the Mannville water handling and injection facilities and related pipeline infrastructure increased the voidage replacement capability by increasing the water available for injection.
- The Company continues to closely monitor performance of the areas of the heavy oil pools under waterflood to inform decisions for future capital expenditures to expand the waterflood project. Results thus far, although very preliminary, have been promising.
- During the fourth quarter, Perpetual divested of several non-core heavy oil properties in eastern Alberta for gross proceeds of $21.6 million, before closing adjustments and transaction costs. Integrating the McDaniel reserve estimates for these assets at year-end 2013, adjusted for 2014 production and internal estimates for reserve additions driven by Perpetual's 2014 capital spending program, the disposition included an estimated 870 Mboe of heavy oil reserves and 4,026 net acres of undeveloped Mannville heavy oil rights. Production from the divestiture package was expected to average approximately 400 to 415 boe/d of primarily heavy oil for the fourth quarter of 2014.

Maximize cash flow from shallow gas

- Capital spending of $8.4 million on Eastern Alberta shallow gas assets concentrated on operations to mitigate production declines on the Corporation's legacy shallow gas assets through facility optimization projects, workovers and uphole recompletions. These projects were low cost optimizations that generally paid out in less than six months.
- High capital efficiency projects arrested the annual decline in Perpetual's shallow gas assets to approximately five percent in 2014. Production additions metrics are estimated to be less than $10,000 per flowing boe, based on forecast 12 month future production for these projects.

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

- Regulatory approval of a pilot project to assess the proprietary LEAD (Low-Pressure Electro-Thermal Assisted Drive) technology was received on July 24, 2014. Project planning and full scale development scoping on Perpetual's bitumen recovery pilot project in the Bluesky formation at Panny led to the initiation of the first phase of the LEAD pilot in the fourth quarter of 2014. Approximately $1 million was spent to prepare for the cyclic heat stimulation test planned for 2015.
- In 2013, Perpetual entered into a farm out agreement to fund the evaluation of prospective acreage in the Duvernay formation at Waskahigan. The vertical stratigraphic test and follow-on horizontal well was rig released in February 2014. The horizontal evaluation well was completed with 16 frac stages late in the third quarter of 2014, with tie in operations commencing during the fourth quarter while the well was shut-in for a pre-production soak period. The non-operated Waskahigan Duvernay horizontal well (35 percent net working interest after completion) commenced production in early March 2015. Production performance will be closely monitored to establish liquids content, gas ratios and production capability as well as other operational parameters to inform the future development and value potential of the Company's 3,072 contiguous net acres in the play.
- In the Columbia area of West Central Alberta, Perpetual continued to monitor production performance of its Fahler horizontal well (0.5 net) as well as competitor activity in several other prospective zones. Plans are developed to gather further information to assess the future development potential of the Company's 16,480 net acres of multi zone, deep basin undeveloped land.
- Two horizontal wells were drilled in the Colorado formation on Perpetual's fee simple acreage in the third quarter of 2014, with gas production commencing from both wells in October 2014. The two wells were part of a larger Colorado horizontal drilling program operated by a competitor and evaluated several different completion techniques. Perpetual will continue to monitor well performance to ascertain optimal completion techniques and drilling strategies to economically develop the Colorado tight shallow gas play in the Mannville area.

2014 FINANCIAL AND OPERATING RESULTS SUMMARY

- Net capital expenditures total $46.7 million during 2014, including $116.5 million on exploration and development activities and net dispositions of $70.4 million. Perpetual also operated $69 million in exploration and development on behalf of the partner as part of the East Edson JV.
- Total production increased ten percent to 20,554 boe/d in 2014 (2013 - 18,696 boe/d) reflecting new production from the 2014 drilling program which continued to be focused on the Company's liquid-rich properties in West Central and heavy oil properties in Mannville as well as highly efficient workover, recompletion and facility optimization projects mitigating shallow gas production declines in eastern Alberta.
- Natural gas production of 102.7 MMcf/d increased 16 percent from 88.9 MMcf/d in 2013, primarily due to production growth at West Edson, which averaged 25.6 MMcf/d (2013 - 10.8 MMcf/d) and East Edson, which averaged 17.7 MMcf/d (2013 - 14.3 MMcf/d). Increases in higher heat content deep basin gas production at East and West Edson more than offset year over year declines in gas production from Perpetual's eastern Alberta assets, which was reduced to just five percent by highly profitable shallow gas optimization projects.
- Oil and NGL production of 3,443 bbl/d was 11 percent lower than in 2013 (3,860 bbl/d). Crude oil production of 2,906 bbl/d (2013 – 3,205 bbl/d) reflected a reduced Mannville heavy oil drilling program compared to 2013 as well as the impact of the non-core heavy oil disposition completed in the fourth quarter. NGL production of 537 bbl/d (2013 – 655 bbl/d) reflected lower average NGL yields on wells drilled at West Edson as well as a change in processing arrangements at both East and West Edson which resulted in previously reported liquids now included as part of higher heat content natural gas sales.

- Deep basin resource-style assets in West Central Alberta contributed 7,649 boe/d of natural gas and associated liquids, representing 37 percent of total production in 2014, up from 26 percent in 2013. High netback Mannville heavy oil production averaged 2,860 boe/d representing 14 percent of total production in 2014.
- Revenue of $262.8 million was 31 percent higher than 2013 ($201.3 million) reflecting increased production and higher average commodity prices in 2014.
- Realized natural gas prices, including derivatives, of $4.36/Mcf in 2014 increased 24 percent from $3.53/Mcf in 2013, reflecting a 40% increase in AECO Monthly Index prices year-over-year, partially offset by losses realized on gas price hedging contracts during 2014. Due to the higher percentage of liquids-rich gas production and processing changes in both West and East Edson, Perpetual's heat content averaged 1.13 GJ/Mcf in 2014 relative to 1.10 GJ/Mcf in 2013.
- Royalty expense of $32.0 million in 2014 represented a combined royalty rate of 12.2 percent compared to 9.4 percent in 2013. An increase in freehold and overriding royalty expense reflected new royalties payable pursuant to the East Edson JV, which entitled the partner to overriding royalties based on a maximum of 5.6 MMcf/d of natural gas from the East Edson property plus oil and associated NGL on a monthly basis beginning July 1, 2014.
- Operating costs decreased another six percent in 2014 to $10.41/boe, down from $11.05/boe in 2013, with absolute savings realized in most areas of operations. Decreased processing fees paid to third parties at both East and West Edson due to the expansion of company-owned and operated infrastructure and re-routing of production led to decreased costs on a unit-of-production basis.
- Operating netbacks increased 15 percent to $17.44/boe (2013 - $15.23/boe) with higher commodity prices and lower operating costs more than offsetting higher transportation costs as well as increased royalties.
- Cash general and administrative expense decreased nine percent to $22.4 million from $24.5 million in 2013, mainly due to higher overhead recoveries from East Edson capital programs and lower consulting and professional fees resulting from cost savings initiatives.
- Funds flow of $81.4 million ($0.55 per share) in 2014 increased 39 percent from $58.5 million ($0.39 per share) in 2013 as a result of increased production, stronger crude oil and natural gas prices and higher operating netbacks in 2014.
- The Corporation recorded net income of $3.4 million ($0.02 per share) compared to $7.6 million ($0.05 per share) in 2013.

2014 RESERVE HIGHLIGHTS

- Perpetual's exploration and development program led to reserve growth of 50.1 MMboe on a proved and probable basis in 2014. Combined with net positive technical revisions of 0.8 MMboe due to performance, total reserve additions of 50.9 MMboe replaced 2014 production of 7.5 MMboe by 680 percent.
- Total proved and probable reserves of 105.5 MMboe at December 31, 2014 were 69 percent higher (67 percent per share) than year-end 2013 (62.4 MMboe), after reflecting net dispositions of 0.7 MMboe in 2014. Similarly proved reserves increased by 22.6 MMboe (66 percent) to 56.7 MMboe from 34.1 MMboe at year-end 2013.
- Reserves from Perpetual's two key diversifying growth plays, liquids-rich gas in the Greater Edson area and Mannville heavy oil in eastern Alberta, represented 77 percent of Perpetual's total proved and probable reserves, up from 59 percent at year-end 2013.
- On a commodity basis, oil and NGL represent nine percent of Perpetual's total proved and probable reserves (nine percent of proved) at December 31, 2014.
- Including changes in future development costs ("FDC"), Perpetual realized finding and development costs ("F&D") of $11.14 per boe in 2014 based on proved and probable reserves. Finding, development and acquisition costs (net of dispositions) ("FD&A") were $9.77 per boe in 2014 based on proved and probable reserves.
- Total proved reserves account for 54 percent (2013 – 55 percent) of total proved and probable reserves at December 31, 2014, while proved and probable developed reserves of 40.7 MMboe represent 39 percent (2013 – 63 percent) of total proved and probable reserves. The increase in the proportion of undeveloped and probable reserves year over year reflects the transformation of a material portion of Perpetual's East Edson Wilrich prospect inventory into recognized reserves.

Reserves Summary

Company Interest Reserves at December 31, 2014[1]

	Light and Medium Crude Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)	Oil Equivalent (Mboe)
Proved Producing	29	1,785	119,356	540	22,246
Proved Non-Producing	48	25	11,715	28	2,053
Proved Undeveloped	14	387	178,505	2,271	32,423
Total Proved	**92**	**2,196**	**309,575**	**2,839**	**56,723**
Probable Producing	12	955	47,452	236	9,111
Probable Non-Producing, excluding Gas Over Bitumen ("GOB")	51	149	22,596	44	4,009
Probable Undeveloped	4	378	178,835	2,166	32,354
Probable Shut-in Gas over Bitumen	-	-	19,878	-	3,313
Total Probable	**67**	**1,482**	**268,761**	**2,445**	**48,788**
Total Proved and Probable	**159**	**3,678**	**578,337**	**5,284**	**105,511**

(1) May not add due to rounding

Future Development Capital[1]

($ millions)	**2015**	**2016**	**2017**	**2018**	**2019**	**Remainder**	**Total**
Eastern Alberta Shallow Gas	1.9	3.4	4.9	0.4	0.2	1.0	11.7
Mannville Heavy Oil	0.3	11.8	-	-	-	-	12.1
Greater Edson Wilrich	108.3	77.1	77.9	70.0	77.5	243.5	654.3
Total	**110.5**	**92.3**	**82.9**	**70.3**	**77.7**	**244.5**	**678.2**

(1) May not add due to rounding

NET ASSET VALUE

- McDaniel's estimate of net present value (discounted at eight percent) (NPV8%) of Perpetual's proved and probable reserves at year-end 2014 was $781.7 million, up 15 percent ($104.8 million) from year-end 2013, despite lower commodity price forecasts, asset dispositions and the monetization of gas over bitumen financial solution related to shut-in reserves.
- Perpetual's reserve-based net asset value ("NAV") - (discounted at eight percent) at year-end 2014 was estimated at $3.99 per share, up 30 percent from $3.07 per share calculated at year-end 2013.

The following net asset value table shows what is referred to as a "produce-out" NAV calculation under which the Corporation's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV represents the fair market value of Perpetual's shares. The calculations below do not reflect the value of the Corporation's prospect inventory to the extent that the prospects are not recognized within the NI 51-101 compliant reserve assessment, except as they are valued through the estimate of the fair market value of undeveloped land.

Net Asset Value[1]

			Discounted at	
($ millions, except as noted)	**Undiscounted**	**5%**	**8%**	**10%**
Total Proved and Probable Reserves[2]	$ 1,467	$ 970	$ 782	$ 685
Fair Market Value of Undeveloped Land[3]	164	164	164	164
Warwick Gas Storage[4]	25	25	25	25
Net Bank Debt[5]	(22)	(22)	(22)	(22)
Convertible Debentures	(35)	(35)	(35)	(35)
Senior Notes	(275)	(275)	(275)	(275)
Estimate of Additional Future Abandonment and Reclamation Costs[6]	(85)	(59)	(48)	(41)
Hedge Book[7]	9	9	9	9
NAV	**$ 1,248**	**$ 777**	**$ 600**	**$ 510**
Shares Outstanding (million) – basic	150	150	150	150
NAV per Share ($/share)	**$ 8.31**	**$ 5.17**	**$ 3.99**	**$ 3.39**

(1) Financial information is per 2014 audited consolidated financial statements. May not add due to rounding.
(2) Reserve values per McDaniel Report as at December 31, 2014, before income taxes.
(3) Independent third party estimate, excludes undeveloped land in West Central Alberta with reserves assigned.
(4) Reflects 30% interest in Warwick Gas Storage at carrying amount.
(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, 2014 relative to McDaniel price forecast.

2015 OUTLOOK

In 2015, Perpetual's top five strategic priorities include:

- Reduce debt and improve debt to cash flow ratio;
- Grow greater Edson liquids-rich gas production, cash flow, inventory, reserves and value;
- Optimize value of Mannville heavy oil;
- Maximize value of shallow gas; and
- Refine elements of production growth strategy for 2017 to 2020.

A strategic transaction was announced on March 12, 2015 to swap Perpetual's joint interest share in its West Edson asset for 6.75 million common shares of Tourmaline Oil Corp. ("TOU Shares") having a market value of approximately $256.5 million based on the closing price of the TOU Shares on the Toronto Stock Exchange. Based on the McDaniel reserve report as at December 31, 2014, the disposition includes 7.2 MMboe of recognized proved and probable developed natural gas and natural gas liquids reserves as well as 16.8 MMboe of proved and probable undeveloped reserves. Also included in the transaction are 9,600 net acres of undeveloped lands not currently assigned reserves at year-end 2014. Perpetual's current production from the West Edson Property is approximately 5,750 boe/d. Based on the current forward market for natural gas and NGL prices, Perpetual estimates the swap of the West Edson Property for TOU Shares will reduce 2015 funds flow by an estimated $15 to $20 million. At the same time, Perpetual will eliminate future 2015 capital spending of approximately $15 million that would have been invested to maintain production from the West Edson Property at current levels.

The Company intends to retain the TOU Shares and systematically manage its obligations, including the redemption of its outstanding convertible debentures (PMT.DB.E) which mature on December 31, 2015. Further, the TOU Shares will be utilized as required to fund the

Company's development plans at East Edson as appropriate in the current commodity price environment and provide additional financial flexibility for Perpetual to capture and evaluate other high impact growth opportunities.

The transaction positions Perpetual to capture the upside of the West Edson property through ownership of the TOU Shares and also provides Perpetual shareholders with the value creation potential inherent in Tourmaline's extensive land and drilling opportunity inventory and strong balance sheet in this period of low commodity prices. At the same time, it materially strengthens Perpetual's present financial situation, augmenting the Company's potential to optimize the shareholder value inherent in its existing diversified portfolio of assets. The TOU Shares also provide greater flexibility to capture and evaluate other new high impact opportunities and pursue strategic initiatives.

Furthermore, the increased liquidity of the TOU Shares relative to the West Edson property positions Perpetual to manage downside risks associated with the current uncertain and volatile commodity price environment. As only 20 percent of the Company's West Edson Property reserves were proved developed reserves at year-end 2014, Perpetual expects the transaction will enhance Perpetual's borrowing capacity. Considering the TOU Shares as an offset to outstanding debt, this transaction drives material positive progress on one of the Company's 2015 strategic priorities, to reduce debt and manage downside risk, bolstering Perpetual's financial flexibility and optionality to manage its future credit facility, convertible debenture and senior note obligations.

As the market value of the TOU Shares approximates the net present value of the proved and probable reserves assigned to the West Edson property, discounted at 10 percent, as assessed by McDaniel at year-end 2014, using McDaniel future commodity price assumptions, the Company estimates that the transaction is neutral on a net asset value basis.

Capital Spending

Perpetual's Board of Directors has approved a first quarter capital expenditure budget of $45 million. Nearly $42 million will be directed to the drilling of six wells (4.5 net) in west central Alberta, with three (1.5 net) at West Edson and three (3.0 net) at East Edson, coupled with the East Edson plant construction activities. All heavy oil drilling has been deferred until oil prices recover, although $1.3 million will be expended to continue to advance the Mannville waterflood projects. Strategic spending at Panny to initiate the first phase of the LEAD pilot project has been reduced to include only capital required to drill two (2.0 net) observation wells associated with the pilot scheme, estimated at $1.2 million.

In light of the extremely uncertain commodity price environment, capital activity for the remainder of the year will be assessed as the year progresses with the intention that spending will be largely funded from funds flow and available bank indebtedness, supplemented by disposition proceeds as crystallized.

FINANCIAL AND OPERATING HIGHLIGHTS

(Cdn$ thousands except volume and per share amounts)	THREE MONTHS Ended December 31 **2014**	2013	Change	YEAR ENDED December 31, **2014**	2013	Change
Financial						
Oil and natural gas revenue	**62,562**	49,075	27%	**262,790**	201,294	31%
Funds flow(1)	**17,316**	12,998	33%	**81,395**	58,468	39%
Per share(1) (2)	**0.12**	0.09	33%	**0.55**	0.39	41%
Net earnings (loss)	**(18,273)**	(13,745)	(33%)	**3,366**	7,620	(56%)
Per share (2)	**(0.12)**	(0.09)	(33%)	**0.02**	0.05	(60%)
Total assets	**750,602**	742,288	1%	**750,602**	742,288	1%
Net bank debt outstanding(1)	**21,867**	67,201	(67%)	**21,867**	67,201	(67%)
Senior notes, at principal amount	**275,000**	150,000	83%	**275,000**	150,000	83%
Convertible debentures, at principal amount	**34,878**	159,779	(78%)	**34,878**	159,779	(78%)
Total net debt(1)	**331,745**	376,980	(12%)	**331,745**	376,980	(12%)
Capital expenditures						
Exploration and development(3)	**26,018**	24,518	6%	**116,457**	96,684	20%
Dispositions, net of Acquisitions	**(20,595)**	(483)	4164%	**(70,351)**	(70,840)	(1%)
Interest in Warwick Gas Storage	**-**	-	-	**-**	19,129	(100%)
Other	**84**	2	4100%	**614**	120	412%
Net capital expenditures	**5,507**	24,037	(77%)	**46,720**	45,093	4%
Common shares outstanding (thousands)						
End of period	**150,077**	148,490	1%	**150,077**	148,490	1%
Weighted average	**149,084**	148,144	1%	**149,084**	148,144	1%
Operating						
Average production						
Natural gas (MMcf/d)(4)	**122.5**	90.3	36%	**102.7**	88.9	16%
Oil and NGL (bbl/d)(4)	**3,262**	3,509	(7%)	**3,443**	3,860	(11%)
Total (boe/d)	**23,685**	18,559	28%	**20,554**	18,696	10%
Average prices						
Natural gas, before derivatives ($/Mcf)	**3.96**	3.37	18%	**4.50**	3.26	38%
Natural gas, including derivatives ($/Mcf)	**4.16**	3.62	15%	**4.36**	3.53	24%
Oil and NGL, before derivatives ($/bbl)	**59.77**	65.35	(9%)	**75.01**	67.65	11%
Oil and NGL, including derivatives ($/bbl)	**64.39**	65.88	(2%)	**71.82**	66.48	8%
Barrel of oil equivalent, including derivatives ($/boe)	**30.40**	30.09	1%	**33.81**	30.56	11%
Drilling (wells drilled gross/net)(5)						
Gas	**11/10.0**	4/2.0		**29/20.9**	6/3.0	
Oil	**-**	5/5.0		**20/17.8**	37/35.7	
Total	**11/10.0**	9/7.0		**49/38.7**	43/38.7	
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 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) Wells drilled includes gas wells drilled as part of the East Edson JV.

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, 2014 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, 2014 and 2013. 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, 2015.

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 calculated by deducting royalties, operating costs, and transportation from total revenue. Operating netbacks are also calculated on a boe basis using average boe production for the period.

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 exploration and evaluation ("E&E") costs, but after payments on the gas over bitumen ("GOB") related financial obligation, as 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)	**2014**	2013	**2014**	2013
Cash flow from operating activities	**17,666**	12,353	**82,082**	52,333
Exploration and evaluation costs(1)	**379**	(19)	**644**	1,279
Payments on financial obligation(2)	**(1,446)**	–	**(2,829)**	–
Expenditures on decommissioning obligations	**2,153**	859	**6,633**	2,497
Changes in long term Crown receivable	**–**	777	**(10,997)**	2,213
Changes in non-cash operating working capital	**(1,436)**	(972)	**5,862**	146
Funds flow	**17,316**	12,998	**81,395**	58,468
Funds flow per share(3)	**0.12**	0.09	**0.55**	0.39

(1) The Corporation expenses exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties and the cost of expired leases 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) These payments are indexed to GOB revenue and recorded as a reduction to the Corporation's financial obligation in accordance with IFRS. To present GOB revenue net of these payments, the Corporation has reclassified these payments from financing to operating activities in the calculation of funds flow.

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

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

GOB revenue, net of payments: GOB revenue, net of payments includes GOB revenue less monthly payments on the GOB related financial obligation. This is used by management to calculate the Corporation's net realized GOB revenue to reflect the substantive monetization of the future GOB royalty credits.

Adjusted working capital deficiency (surplus): Adjusted working capital deficiency (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, current portion of financial obligation, current portion of convertible debentures 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 deficiency (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:1bbl 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 AND STATEMENTS: Certain information and statements contained in this MD&A including management's assessment of future plans and operations and including the information contained under the heading "2015 Outlook" may 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", "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 financial contracts 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, general and administrative ("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 expenditure program; expected compliance with credit facility covenants in 2015 and 2016; 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; future income tax and its effect on funds flow; intentions with respect to preservation of tax pools 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)	**2014**	2013	2012
Financial			
Oil and natural gas revenue	**262,790**	201,294	176,137
Net income (loss)	**3,366**	7,620	(75,986)
Per share(1)	**0.02**	0.05	(0.52)
Funds flow	**81,395**	58,468	49,087
Per share(1)	**0.55**	0.39	0.33
Total assets	**750,602**	742,288	729,888
Total long term liabilities	**507,296**	513,836	594,342
Net bank debt outstanding	**21,867**	67,201	77,827
Senior notes, at principal amount	**275,000**	150,000	150,000
Convertible debentures, at principal amount	**34,878**	159,779	159,972
Total net debt	**331,745**	376,980	387,799
Capital expenditures			
Exploration and development(2)	**116,457**	96,684	79,724
Dispositions, net of acquisitions	**(70,351)**	(70,840)	(164,763)
Interest in Warwick Gas Storage ("WGS LP")	**–**	19,129	–
Other	**614**	120	271
Net capital expenditures	**46,720**	45,093	(84,768)
Shares outstanding (thousands)			
End of period	**150,077**	148,490	147,455
Weighted average	**149,084**	148,144	147,085
Operating			
Average production			
Natural gas (MMcf/d)	**102.7**	88.9	100.2
Oil and NGL (bbl/d)	**3,443**	3,860	3,448
Total average production (boe/d)	**20,554**	18,696	20,142
Average prices			
Natural gas – before derivatives ($/Mcf)	**4.50**	3.26	2.48
Natural gas – including derivatives ($/Mcf)	**4.36**	3.53	3.34
Oil and NGL – before derivatives ($/bbl)	**75.01**	67.65	64.26
Oil and NGL – including derivatives ($/bbl)	**71.82**	66.48	64.13
Wells drilled			
Natural gas – gross (net)	**29 (20.9)**	6 (3.0)	8 (5.5)
Crude oil – gross (net)	**20 (17.8)**	37 (35.7)	36 (34.6)
Total – gross (net)	**49 (38.7)**	43 (38.7)	44 (40.1)

(1) Based on weighted average shares outstanding for the year.
(2) Exploration and development costs include geological and geophysical expenditures.

OVERALL PERFORMANCE

Perpetual focused on five key strategic priorities in 2014:

- 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 the portfolio of high impact opportunities with risk-managed investment.

During 2014, Perpetual accelerated the development of its West Central liquid-rich natural gas by maintaining focus on development activities in the Greater Edson area. At West Edson, a facility expansion increased capacity to 60 MMcf/d (30 MMcf/d net), while drilling activity throughout 2014 continues to maintain the new plant at full capacity. During the second half of 2014, Perpetual's capital program focused on East Edson as a result of the East Edson royalty disposition and farm-in agreement ("East Edson Agreements"). The arrangement included the disposition of a 50 percent royalty interest in the current developed producing reserves in the East Edson area (the "Producing Royalty") for net cash proceeds of $47 million. Net cash proceeds consisted of $17 million of unrestricted cash that was applied to reduce bank indebtedness, with the remaining $30 million held in escrow to be used for development spending in East Edson. Concurrent with the royalty disposition, Perpetual also entered into a farm-in agreement, whereby the partner contributed $70 million to an escrow account to fund the drilling, completion and tie-in of 13 horizontal wells in the Wilrich formation in exchange for a second royalty (the "Drilling Royalty") on new production from the East Edson property. When taking into account both agreements, in exchange for the total acquisition and funding commitment of $120 million net of adjustments, the Drilling and Producing Royalties entitle the partner to receive, on a priority basis, a maximum of 5.6 MMcf/d of natural gas from the East Edson property plus associated NGL from July 1, 2014 to December 31, 2022 and declining thereafter at 10 percent per year until the Drilling Royalty and the Producing Royalty ("East Edson Gross Overriding Royalty") terminate on December 31, 2034. The Producing Royalty also included a 50 percent gross overriding royalty on existing minor oil production.

Pursuant to the East Edson Agreements, Perpetual committed to spend $30 million to drill, complete and tie-in approximately five wells prior to December 31, 2015, substantially following the spending of the $70 million commitment by the partner. The majority of the partner's $70 million commitment and a portion of Perpetual's first $30 million commitment were spent by the end of 2014, with the balance expected to be fully spent by the end of the first quarter of 2015. In addition, Perpetual committed to construct a new gas plant at East Edson to add 30 MMcf/d of processing capacity at an estimated cost of $30 million. Spending on the gas plant began in 2014 with startup expected in the third quarter of 2015. Finally, Perpetual also committed to invest an additional $30 million to drill, complete and tie-in approximately six additional wells prior to December 31, 2022.

The combined capital programs of East and West Edson resulted in 28 (20.6 net) wells drilled in 2014 compared to six (3.0 net) wells drilled in 2013 in the Greater Edson area. Thirteen (13.0 net) East Edson wells were drilled utilizing partner funds from escrow pursuant to the East Edson Agreements.

Perpetual also continued its development of heavy oil assets in the Mannville area during 2014 which included drilling 20 (17.8 net) wells, as well as expenditures related to the initiation of waterflood operations in several larger pools. Capital activities in 2014 also included optimization activities on Perpetual's Eastern Alberta shallow gas assets which mitigated declines and reduced operating costs in these areas.

As a result of Perpetual's 2014 capital initiatives, proved plus probable reserves increased by 70 percent since year end 2013 to 105.5 MMBoe. Oil and natural gas production during 2014 increased ten percent to 20,554 boe/d from 18,696 boe/d in 2013. Higher production, combined with improved year over year commodity prices and lower unit operating costs, drove funds flow up 39 percent to $81.4 million in 2014 from $58.5 million in 2013.

Perpetual reduced year-end net debt by 12 percent to $331.7 million at December 31, 2014 from $377.0 million at the end of 2013, primarily as a result of proceeds received from the monetization of GOB royalty credits, the East Edson royalty disposition, the sale of non-core heavy oil assets and funds flow which more than offset 2014 net capital spending. In addition, Perpetual issued $125 million in senior unsecured notes ("2014 Senior Notes"). The combination of proceeds received from dispositions and the senior notes offering were used to early redeem all the outstanding $99.9 million 7.25 percent convertible debentures ("7.25% Debentures") which were due to mature on January 31, 2015 as well as $25 million of the $59.9 million 7.00 percent convertible debentures ("7.0% Debentures") maturing on December 31, 2015. These transactions supported the positive progress on the Corporation's 2014 strategic priority to reduce debt and manage downside risk. The reduction to total net debt combined with the issuance of senior notes in 2014 bolstered Perpetual's financial flexibility by effectively extending the term for the majority of the Company's debt to 2018 and 2019.

2014 FINANCIAL RESULTS

Capital expenditures

($ thousands)	**2014**	2013
Exploration and development	**115,813**	95,405
Geological and geophysical costs[(1)]	**644**	1,279
Acquisitions	**998**	8,135
Dispositions	**(71,349)**	(78,975)
Interest in WGS LP	**–**	19,129
Other	**614**	120
Total[(2)]	**46,720**	45,093

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

(2) This table excludes $21.3 million in proceeds related to the monetization of GOB royalty credits.

Exploration and development spending by area

($ thousands)	**2014**	2013
West Central liquids-rich gas[(1)]	**81,096**	42,360
Mannville heavy oil	**24,559**	49,316
Shallow gas and other	**10,157**	3,729
Total	**115,812**	95,405

(1) Excludes partner spending from the $70 million escrow account in relation to the East Edson Agreements.

Total exploration and development expenditures, including geological and geophysical expenditures, of $116.4 million during 2014 were focused largely on liquids-rich natural gas development activities in the Corporation's West Central district as well as continued heavy oil development at Mannville.

At East Edson, the Corporation commenced its planned drilling program immediately after closing the East Edson Agreements in July 2014, drawing on the majority of the $70 million of farm-in funds established in the partner escrow account before year-end. During 2014, 13 (13.0 net) wells were drilled as part of the East Edson farm-in agreement and financed from the partner's escrow account. These costs are not included as part of Perpetual's reported capital expenditures. In total, 15 (15.0 net) wells were drilled in East Edson during 2014, including the 13 (13.0 net) wells financed from the partner's escrow account and two (2.0 net) additional wells drilled prior to closing of the East Edson Agreements. Nine (9.0 net) of the horizontal wells drilled were within the Northeast development area and six (6.0 net) within the southwest development area. Most of the wells are producing well above their respective proved plus probable independent reserve evaluations type curves. In addition to spending on drilling and completion projects, a 3D seismic survey covering a portion of the East Edson Agreement lands was undertaken and substantially completed during 2014.

In addition to the development spending funded by the partner's capital commitment, Perpetual satisfied $13.3 million of its $30 million exploration and development commitment under the East Edson Agreements and spent an additional $14 million on procurement and site preparation for the new 30 MMcf/d gas plant. The new gas plant is on track to be completed on budget and operational for start-up during the third quarter of 2015.

In West Edson, development of the Corporation's liquids-rich gas was accelerated with drilling after spring breakup targeted to fill the expanded plant capacity of 60 MMcf/d (30 MMcf/d net). During 2014, $44.7 million of expenditures were directed almost exclusively to drilling, completion and tie-in operations at West Edson with the addition of 11 (5.5 net) operated wells and two additional (0.1 net) non-operated wells. The operated wells have performed consistently at or above the proved plus probable independent reserve evaluations type curve. The facility was operating at maximum capacity beginning in early August and is expected to remain at or near capacity through 2020 based on the Corporation's forecast drilling operations.

Exploration and development spending of $24.6 million at Mannville during 2014 included the drilling and completion of 20 (17.8 net) horizontal heavy oil wells, down from 37 (35.7 net) in 2013, as well as the conversion of seven wells to waterflood injection wells and expenditures for related pipelines and facilities.

Spending of $10.2 million on Eastern Alberta shallow gas and other assets during the year was primarily related to facility projects, with $3.2 million spent on recompletion and workover programs. These projects were low cost optimizations that generally paid out in less than six months. High capital efficiency recompletion projects, combined with workovers and facility optimization work, arrested the decline in Perpetual's shallow gas assets to five percent in 2014.

During 2014, a farm out commitment well was drilled and completed on Perpetual's behalf, targeting the Duvernay formation in the Waskahigan area. Perpetual retained a 35% working interest in the well and spent $1.2 million toward the equipping and tie-in of this well. The horizontal Duvernay well is expected to commence production in early March 2015.

Acquisitions and dispositions

In addition to the East Edson Agreements, cash proceeds on dispositions, net of acquisitions of $70.4 million during 2014 included the disposition of non-core Mannville heavy oil assets for net proceeds of $21.4 million and the sale of certain undeveloped land for net proceeds of approximately $3.0 million, which included the sale of land acquired through a non-cash swap transaction in the first quarter of 2014. Dispositions net of acquisitions for the same period of 2013 of $70.8 million primarily related to the Elmworth property disposition.

Gas over bitumen monetization

Perpetual receives GOB royalty credits under the Natural Gas Royalty Regulation as a result of its working interests in a number of natural gas wells which have been shut-in pursuant to shut-in orders issued by the Government of Alberta. In 2014, Perpetual closed two transactions which effectively monetized the majority of its future GOB royalty credits associated with certain shut-in properties in northeast Alberta for net proceeds of $21.3 million. In exchange for the proceeds, Perpetual makes monthly payments to the purchaser which are based on the GOB formula set out in the Alberta Gas Royalty Regulations. Under IFRS, this transaction has been accounted for as a hybrid financial obligation, which is adjusted to fair value each reporting period. Monthly payments are recorded as a reduction of the outstanding obligation.

Production

	2014	2013
Natural gas (MMcf/d)		
Eastern – North	**36.4**	38.5
Eastern – South	**23.8**	25.2
West Central	**42.5**	25.2
Total natural gas	**102.7**	88.9
Crude oil (bbl/d)		
Eastern – North	**6**	7
Eastern – South(1)	**2,860**	3,150
West Central	**40**	48
Total crude oil	**2,906**	3,205
NGL (bbl/d)		
Eastern – South	**11**	9
West Central	**526**	646
Total NGL	**537**	655
Total production (boe/d)	**20,554**	18,696

(1) Primarily Mannville heavy oil.

Total natural gas, NGL and oil production in 2014 of 20,554 boe/d was ten percent higher than 2013 (18,696 boe/d) due to increased natural gas production from the West Central district. Production from new wells filled the expanded plant capacity with higher heat content sales gas at West Edson. In addition, production increases were also attributable to new East Edson production resulting from an extensive capital program in the third and fourth quarters pursuant to the East Edson Agreements. Production increases from the Greater Edson area more than offset production declines in the Company's other operating areas.

Perpetual's 2014 natural gas production of 102.7 MMcf/d increased 16 percent from 88.9 MMcf/d in 2013. Increased gas production in 2014 was driven by growth in West Edson production, which averaged 25.6 MMcf/d (2013 - 10.8 MMcf/d) and East Edson production, which averaged 17.7 MMcf/d (2013 - 14.3 MMcf/d). Edson processing facilities were operating at full capacity at the end of 2014. Increases in East Edson production and higher heat content deep basin gas production at West Edson more than offset year over year declines in production from Perpetual's shallow gas assets.

Oil production of 2,906 bbl/d in 2014 decreased from 3,205 bbl/d in 2013 as fewer Mannville heavy oil wells were drilled in 2014 with Mannville capital directed to waterflood activities. As a result, production declines offset new production additions as the new drill well count decreased to 20 (17.8 net) in 2014 as compared to 37 (35.7 net) in 2013.

Despite higher gas production in West Central Alberta, NGL production of 537 bbl/d reflected reduced NGL yields in 2014 from the Corporation's Greater Edson area. West Central NGL yields during 2014 dropped to 12.4 bbl/MMcf from 26 bbl/MMcf for the same period in 2013 as high liquids yield wells at East Edson declined and spending continued to be focused at West Edson where liquids yields are lower than at East Edson. In addition, the change in processing arrangements in West Edson, which started up operations on October 1, 2013, reduced the reported liquids recovery. East Edson reported liquids yields were also reduced by changes in processing as economics, turnarounds and capacity considerations resulted in Perpetual processing its gas through its working interest in the Rosevear plant during all of 2014 rather than the third party deep cut plant in which the majority of gas was processed during 2013. A portion of the previously recovered liquids have been included in higher heat content gas sales during all of 2014 versus just the fourth quarter of 2013. The result is a higher realized gas price and, at the same time, higher grade liquids are now recovered and marketed.

Perpetual no longer reports deemed production as Perpetual entered into transactions in 2014 to monetize its future GOB royalty credits for the vast majority of the Corporation's remaining future royalty credit entitlements. These transactions are accounted for as a financial obligation under IFRS.

Commodity prices

	2014	2013
Reference prices		
AECO Monthly Index ($/Mcf)(1)	**4.41**	3.16
AECO Daily Index ($/Mcf)(1)	**4.50**	3.17
Alberta Gas Reference Price ($/Mcf)(2)	**4.21**	2.82
West Texas Intermediate ("WTI") light oil ($USD/bbl)	**93.00**	97.97
Western Canadian Select ("WCS") differential ($USD/bbl)	**(19.40)**	(25.20)
Average Perpetual prices		
Natural gas		
Before derivatives ($/Mcf)(3)(4)	**4.50**	3.26
Percent of AECO Monthly Index	**102**	103
Including derivatives ($/Mcf)	**4.36**	3.53
Percent of AECO Monthly Index	**99**	112
Oil and NGL		
Before derivatives ($/bbl)	**75.01**	67.65
Including derivatives ($/bbl)	**71.82**	66.48
Barrel of oil equivalent		
Average realized price ($/boe)	**33.81**	30.56

(1) AECO Index prices are reported in $/GJ and have been converted at a ratio of 1.05 GJ: 1 Mcf.
(2) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.
(3) 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.
(4) The average conversion ratio for Perpetual's 2014 natural gas production is 1.10 GJ: 1 Mcf.

AECO Monthly Index prices of $4.41/Mcf in 2014 increased 40 percent from $3.16/Mcf for the same period in 2013. Price appreciation during the first quarter of 2014 was caused by extreme cold weather that led to strong heating demand and significantly depleted natural gas storage levels by the end of the 2014 withdrawal season. The year over year storage deficit was rebuilt as reduced cooling demand in the third quarter allowed strong injections and a warmer than normal fourth quarter contributed to lower early winter storage withdrawals. With gas storage levels back to seasonal norms, continued year over year increases in North American production caused gas prices to decline from the higher prices realized in the first half of 2014.

Increased average AECO Monthly Index prices in 2014 were reflected in Perpetual's natural gas price before derivatives with a year over year increase of 38 percent. In addition, an increased volume of higher heat content natural gas associated with West Central production, combined with the Aux Sable and Alliance Pipeline marketing and transportation agreements in 2014, allowed Perpetual to realize a higher average natural gas price relative to 2013.

Perpetual's average realized gas price, including derivatives, increased 24 percent to $4.36/Mcf in 2014 from $3.53/Mcf for the same period in 2013. Realized losses of $5.1 million on financial natural gas contracts for the year ended December 31, 2014 were partially offset by $0.4 million realized on the monetization of gains on natural gas contracts during the first quarter of 2014. Realized losses led to an average 2014 gas price that was 99 percent of the AECO Monthly Index.

Perpetual's oil and NGL price, before derivatives, of $75.01/bbl in 2014 increased 11 percent compared to the same period in 2013 due to strong WTI prices during the first half of 2014 which, along with a narrowing of WCS differentials, offset by the effect of price declines realized in the fourth quarter. In addition, the delivery of higher grade oil resulting from new drying operations at the majority of the Mannville heavy oil production pads as well as higher grade NGL sales from processing changes which affected the liquids recoveries at East and West Edson, contributed to improved pricing.

Perpetual's realized oil and NGL price, including derivatives, was four percent lower than the price before derivatives in 2014, primarily due to economic hedging losses recorded on financial WTI price contracts during the first three quarters of 2014 which more than offset gains realized during the fourth quarter of 2014 as oil prices declined. Losses on financial WTI contracts for the year ended December 31, 2014 were $3.9 million compared to $2.6 million for the same period in 2013.

Commodity price risk management

Perpetual's commodity price 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 financial contracts on an estimated 52 percent of forecasted actual natural gas production for the remainder of 2015. The following tables provide a summary of derivative natural gas contracts in place as at December 31, 2014, as well as any additional contracts entered into prior to the date of this MD&A.

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

Term	Volumes sold (bought) at AECO (GJ/d)	Average price ($/GJ)(1)	Market prices ($/GJ)(2)	Type of contract
January 2015	10,000	4.23	3.19	Financial
January 2015	(10,000)	3.35	3.19	Physical
February 2015	82,065	2.81	2.60	Financial
February 2015	16,500	2.63	2.60	Physical
March 2015	82,500	2.83	2.59	Financial
March 2015	44,500	2.61	2.59	Physical
March 2015	(24,500)	2.48	2.59	Physical
April 2015 – June 2015	102,500	2.57	2.53	Financial
April 2015 – June 2015	(10,000)	2.52	2.53	Financial
July 2015 – October 2015	82,500	2.56	2.61	Financial
November 2015 – December 2015	7,500	2.78	2.90	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for January to March are based on settled AECO Monthly Index prices. Market prices for subsequent months are based on forward AECO prices as of market close on March 4, 2015.

Crude Oil

The following tables provide a summary of derivative crude oil contracts in place as at December 31, 2014, as well as any additional contracts entered into prior to the date of this MD&A.

Costless collar oil sales arrangements in Cdn$:

Term	Volumes (bbl/d)	Floor price (Cdn$/bbl)	Ceiling price (Cdn$/bbl)	Market prices (Cdn$/bbl)(1)	Type of contract
January 2015 – February 2015	500	87.50	95.25	60.37	Collar
January 2015 – February 2015	500	87.50	95.75	60.37	Collar
March 2015 – December 2015	500	87.50	95.25	71.06	Collar
March 2015 – December 2015	500	87.50	95.75	71.06	Collar

(1) Market prices for January and February are based on settled WTI oil prices at settled foreign exchange rates. Market prices for subsequent months are based on forward WTI oil prices at a forward foreign exchange rate of 1.245 as of market close on March 4 2015.

Sold oil call options with monthly expiry over the contract term:

Term	Volumes at WTI (bbl/d)	Call price (US$/bbl WTI)	Market prices (US$/bbl WTI)(1)	Type of contract
January 2016 – December 2016(2)	500	106.00	62.34	Knock out call
January 2016 – December 2016(3)	1,000	104.25	62.34	Knock out call

(1) Market prices are based on forward WTI oil prices as of market close on March 4, 2015.
(2) If WTI index settles above US$106.00/bbl in any month, the contract is settled at US$97.00/bbl for that month.
(3) If WTI index settles above US$104.25/bbl in any month, the contract is settled at US$95.40/bbl for that month.

Basis differential contracts between WTI and WCS trading:

Term	Volumes (bbl/d)	WTI-WCS differential (US$/bbl)(1)	Market prices (US$/bbl)(2)	Type of contract
January – March 2015	1,000	(16.88)	(14.73)	Financial
April - December 2015	1,000	(16.88)	(14.90)	Financial

(1) Average price calculated using weighted average price for net open contracts; contracts settle at WTI index less a fixed basis amount.
(2) Market prices for January to March are based on settled WTI-WCS differential prices. Market prices for subsequent months are based on forward WTI-WCS differential prices as of market close on March 4, 2015.

Foreign Exchange

U.S. dollar forward sales arrangements:

Term	Notional US$/month	Exchange rate (Cdn$/US$)	Type of contract
January – June 2015	1,000,000	1.10	Financial

The Corporation receives $1,000 each day during the month that the daily exchange rate is between 1.00 and 1.10. If the average monthly exchange rate is greater than 1.10 the Corporation pays US$1,000,000 multiplied by the difference between the average monthly exchange rate and 1.10. No settlement occurs between the Corporation and the counterparty if the average monthly exchange rate settles below 1.00.

Term	Notional floor US$/month	Notional ceiling US$/month	Exchange rate floor (Cdn$/US$)	Exchange rate ceiling (Cdn$/US$)	Type of contract
January 2015 – December 2016	2,000,000	3,500,000	1.04	1.18	Financial

If the average monthly exchange rate is greater than the exchange rate ceiling, the Corporation pays US$3,500,000 multiplied by the difference between the average monthly exchange rate and 1.127. If the monthly average exchange rate settles below the exchange rate floor, the Corporation receives US$2,000,000 multiplied by the difference between the average monthly exchange rate and the exchange rate floor.

Revenue

($ thousands, except as noted)	**2014**	2013
Petroleum and natural gas revenue		
Natural gas(1)	**168,521**	105,965
Oil and NGL(1)	**94,269**	95,329
Total petroleum and natural gas revenue	**262,790**	201,294
Other revenue		
Unrealized gains (losses) on derivatives	**11,946**	1,783
Realized gains (losses) on derivatives	**(9,127)**	6,275
Total other revenue	**2,819**	8,058
Total revenue	**265,609**	209,352
Per boe	**35.41**	30.68

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

Perpetual's petroleum and natural gas ("P&NG") revenue, before derivatives, increased 31 percent to $262.8 million in 2014 (2013 - $201.3 million) primarily due to improved pricing and increased West Central natural gas production. The impact of new production from capital spending under the East Edson Agreements also began to be realized late in the fourth quarter of 2014.

Natural gas revenue, before derivatives, of $168.5 million in 2014 was 59 percent higher than the prior year. Higher heat content production from West Central deep basin accounted for 37 percent of total natural gas production translating into realized natural gas prices that are ten percent higher compared to dry shallow gas prices.

Oil and NGL revenues, before derivatives, of $94.3 million in 2014 were marginally lower than $95.3 reported in 2013. Decreased oil and NGL revenue was a result of lower oil production as recent capital activity has focused on development of liquids-rich natural gas in West Central

Alberta and lower NGL sales related to changes in processing in the Edson area. Production declines were largely offset by higher WTI prices during the majority of 2014. The recent global decline in oil prices affected revenue in the latter part of the fourth quarter of 2014.

Realized losses on derivatives in 2014 totaled $9.1 million compared to gains of $6.3 million in 2013. Losses in 2014 were comprised of $5.1 million and $4.0 million related to natural gas and oil contracts respectively, which were partially offset by $0.4 million of crystallized gains on certain economic hedging contracts.

The Corporation recorded unrealized gains on derivatives of $11.9 million during 2014 compared to a gain of $1.8 million in 2013. Unrealized gains and losses represent the change in mark-to-market values 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, vary with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

Royalties

($ thousands except as noted)	**2014**	2013
Crown	**15,130**	9,924
Freehold and overriding(1)	**16,894**	9,118
Total	**32,024**	19,042
Crown (% of total P&NG sales)	**5.8%**	4.9%
Freehold and overriding (% of total P&NG sales)	**6.4%**	4.5%
Total (% of P&NG sales)	**12.2%**	9.4%
Per boe	**4.27**	2.79

(1) Includes $5.2 million in East Edson Gross Overriding Royalties paid as part of the East Edson Agreements in 2014.

Perpetual recorded royalty expense of $32.0 million in 2014, representing an increase in the combined royalty rate to 12.2 percent compared to 9.4 percent in 2013. The increase in freehold and overriding royalty expense was consistent with Perpetual's East Edson royalty disposition and farm-in agreements which included the sale of Drilling and Producing Royalties which entitle the partner to a maximum of 5.6 MMcf/d of natural gas from the East Edson property plus oil and associated NGL on a monthly basis beginning July 1, 2014. Excluding royalty payments of $5.2 million under the East Edson Agreements, the combined royalty rate for 2014 was 10.2 percent, which was still above the prior year as a result of increases to Crown royalty rates associated with higher Alberta gas reference prices. In addition, certain of the Corporation's Mannville heavy oil wells continue to transition to higher royalty rates after reaching maximum volume recoveries under initial low royalty rate incentive periods.

Production and operating expenses

($ thousands except as noted)	**2014**	2013
Production and operating expenses	**78,128**	75,414
Per boe	**10.41**	11.05

With the ten percent increase in production in 2014, total production and operating expenses of $78.1 million were only four percent higher than $75.4 million in 2013 reflecting increased operating efficiencies and cost reductions related to the reclassification of oil trucking fees at Mannville to transportation costs. On a boe basis, operating costs decreased in 2014 to $10.41/boe from $11.05/boe in 2013. Operating cost per boe savings relate primarily to infrastructure expansion and enhancements at West Edson, resulting in decreased processing fees paid to third parties and increased efficiency on a unit-of-production basis. Additional savings were realized by redirecting East Edson volumes from a third party deep cut plant to Perpetual's working interest plant at Rosevear. Further operational efficiencies have been realized as a result of pipeline suspensions in eastern Alberta combined with Perpetual's company-wide cost saving initiatives. Property taxes in eastern Alberta continue to be extremely high relative to operating netbacks for these shallow gas properties. Approximately 88 percent of the property taxes paid in 2014 ($8.9 million) relate to assets in Eastern Alberta. As operating costs are also relatively high for these assets, Eastern Alberta property taxes were 17 percent of operating expenses for Eastern Alberta in 2014 and reduced the Company's operating netbacks in eastern Alberta by close to 27 percent.

Transportation costs

($ thousands except as noted)	**2014**	2013
Transportation costs	**12,684**	10,163
Per boe	**1.69**	1.49

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 2014 increased to $12.7 million from $10.2 million in 2013, primarily due to increased Mannville oil transportation costs and higher natural gas sales volumes. Perpetual has increased its onsite processing of oil at Mannville to meet sales point specifications, primarily to allow increased volumes to be transported by rail. This resulted in a change in classification from operating costs (emulsion trucking) to transportation costs (clean oil trucking). The change to onsite processing has enhanced oil marketing opportunities and improved the overall netback for heavy oil production from the Mannville area.

Operating netbacks

	2014	2013
Operating netback *($ thousands)*		
Realized revenue [(1)]	**253,663**	208,522
Royalties[(2)]	**(32,024)**	(19,042)
Operating costs	**(78,128)**	(75,414)
Transportation	**(12,684)**	(10,163)
Total operating netback	**130,827**	103,903
Boe operating netback *($/boe)*		
Realized revenue [(1)]	**33.81**	30.56
Royalties	**(4.27)**	(2.79)
Operating costs	**(10.41)**	(11.05)
Transportation	**(1.69)**	(1.49)
Boe operating netback	**17.44**	15.23

(1) See "Non-GAAP measures" in this MD&A.
(2) Includes $5.2 million in East Edson Gross Overriding Royalty payments in relation to the East Edson Agreements in 2014.

Perpetual's 2014 operating netback of $17.44/boe ($130.8 million) increased 15 percent from $15.23/boe ($103.9 million) in 2013, with increased revenue more than offsetting higher transportation costs and increased royalty expenses associated with the East Edson gross overriding royalty beginning on July 1, 2014. Operating netbacks in 2014 excluding royalties paid under the East Edson Agreements were $18.13 /boe ($136.0 million).

Gas over bitumen revenue

($ thousands except as noted)	**2014**	2013
Gas over bitumen revenue	**8,888**	8,905
Payments on financial obligation	**(2,829)**	–
Gas over bitumen revenue, net of payments	**6,059**	8,905
Per boe	**0.81**	1.30

Perpetual records revenue in relation to GOB royalty credits received under the Natural Gas Royalty Regulation as a result of its working interests in a number of natural gas wells which have been shut-in pursuant to shut-in orders issued by the Government of Alberta. During 2014, Perpetual recorded $8.9 million in GOB revenue which was consistent with the same period in 2013 as the annual 10 percent decline in deemed production was offset by higher Alberta reference prices.

Gas over bitumen financial obligation

($ thousands except as noted)	**2014**
Balance, beginning of year	**–**
Additions	**21,254**
Payments	**(2,829)**
Change in fair value of financial obligation	**(3,035)**
Balance, end of year	**15,390**

In 2014, Perpetual closed transactions to effectively monetize the majority of its future GOB royalty credits associated with certain shut-in properties in northeast Alberta. After closing adjustments, Perpetual received net proceeds of $21.3 million for these transactions. In exchange for the proceeds, Perpetual makes monthly payments to the purchaser which are based on the GOB formula set out in the Alberta Gas Royalty Regulations. Pursuant to the terms of the agreement, in the event that the annual average Alberta Gas Reference Price is higher than a price based on the January 1, 2014 price forecast defined in the agreement, the payment will be adjusted for differences between the actual Alberta Gas Reference price and the January 1, 2014 price forecast, with the Corporation retaining 35 percent of any excess resulting from Alberta Gas Reference prices exceeding a January 1, 2014 third party evaluators price forecast. The monthly payment commitment expires concurrent with the GOB Royalty Adjustment entitlements, with final expiries expected to occur in June 2021. Further, none of the GOB credits included under the monetization transaction have repayment obligations as the underlying shut-in wells were sold in 2010, at which time the liability for future repayment was assumed by the purchasers. As such, the monetization transaction had no impact on the Corporation's recorded GOB obligation.

Under IFRS, this transaction is accounted for as a hybrid financial instrument including a financial host contract obligation with an embedded derivative related to the indexation of the future cash payments to changes in the future Alberta gas reference price. The financial obligation will be restated to fair value each reporting period with monthly payments applied against the obligation. GOB revenue will continue to be recognized separately as revenue in accordance with Perpetual's accounting policies; however, for the purposes of this MD&A, the monthly payments have been included as a reduction to GOB revenue to reflect the substantive monetization of the future GOB royalty credits.

Exploration and evaluation

($ thousands)	**2014**	2013
Lease rentals	**3,165**	3,269
Geological and geophysical costs[1]	**644**	1,279
Lease expiries	**2,135**	2,715
Total exploration and evaluation	**5,944**	7,263

(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.

E&E costs include lease rentals on undeveloped acreage, geological and geophysical costs and lease expiries. E&E costs of $5.9 million in 2014 were $1.4 million lower than the prior year manly due to reduced spending on seismic data.

General and administrative expenses

($ thousands except as noted)	**2014**	2013
Cash general and administrative expense	**22,371**	24,509
Share based compensation expense (non-cash)	**5,972**	3,974
Total general and administrative expense	**28,343**	28,483
Cash general and administrative expense – per boe	**2.98**	3.59
Share based compensation expense (non-cash) ($/boe)	**0.80**	0.58

Cash general and administrative ("G&A") expense for 2014 decreased nine percent to $22.4 million from $24.5 million in 2013, mainly due to higher overhead recoveries from East Edson capital programs as well as lower consulting and professional fees related to Perpetual's cost savings initiatives. Non-cash compensation expenses in 2014 was $6.0 million, up from $4.0 million in 2013 as a result of performance multiplier adjustments related to performance share units issued and outstanding, along with the initial vesting of units granted in the current year.

Impairment

At December 31, 2014, indicators of potential impairment were identified and Perpetual measured the carrying values of each of its cash generating units ("CGUs"), less the corresponding decommissioning obligations, against the estimated recoverable amount based on value in use which Perpetual deemed to be higher compared to fair value less cost to sell. A net impairment loss of $21.4 million was recorded for 2014 consisting of a $26.4 million impairment loss recorded within the Birchwavy East CGU due to lower forecasted oil prices. This impairment loss was partially offset by the reversal of previous year's impairment charges of $5.0 million within the Birchwavy West CGU due to the underlying assets demonstrating sustainable operational performance since the last calculation of the recoverable amount.

In 2013 Perpetual recorded the reversal of a previous years' impairment charge of $5.2 million on assets geographically located within the West Central CGU. Impairments were reversed primarily due to positive reserve revisions related to the strong performance of Perpetual's wells in West Edson.

Depletion and depreciation

($ thousands except as noted)	**2014**	2013
Depletion and depreciation	**94,736**	92,877
Per boe	**12.63**	13.61

Perpetual recorded $94.7 million ($12.63/boe) of depletion and depreciation expense in 2014, compared to $92.9 million ($13.61/boe) in 2013. The decrease in depletion rates per boe in 2014 is consistent with increased reserves largely due to reserve additions recognized with the committed development of the East Edson assets.

Finance expenses

Interest

($ thousands)	**2014**	2013
Cash interest		
Senior notes	**17,670**	13,125
Convertible debentures	**8,912**	11,423
Bank debt	**3,373**	4,384
Total cash interest	**29,955**	28,932
Non-cash interest		
Amortization of debt issue costs	**3,384**	3,545
Loss on redemption of convertible debentures	**1,512**	5
Total non-cash interest	**4,896**	3,550
Total Interest	**34,851**	32,482

Despite lower overall debt levels, interest expense during 2014 was seven percent higher than 2013, primarily associated with non-cash losses of $1.5 million related to the early redemption of the 7.25% Debentures in August, 2014 and partial redemption of the 7.00% Debentures in December 2014. Increased cash interest from the issuance of 8.75% senior notes, which carry a higher interest rate than the 7.25% Debentures, was partially offset by reduced short term borrowing costs due to lower levels of bank debt.

Other finance expenses

($ thousands)	**2014**	2013
Accretion on decommissioning obligations	**5,400**	4,439
Accretion and change in estimate on GOB obligation	**376**	211
Change in fair value of financial obligation	**(3,035)**	–
Loss (gain) on marketable securities	**–**	92
Loss (gain) on call option	**–**	1,274
Other finance expenses	**2,741**	6,016

Other finance expenses in 2014 included accretion on decommissioning obligations of $5.4 million (2013 – $4.4 million), accretion and change in estimate on the GOB Obligation of $0.4 million (2013 – $0.2 million) and an unrealized gain of $3.0 million due to a change in the fair value of the financial obligation, related to the GOB monetization (2013 – nil). In 2013, a loss of $1.3 million was recorded during the first quarter in relation to the expiry and partial exercise of Perpetual's option to repurchase up to a 30 percent interest in Warwick Gas Storage LP ("WGS LP").

Gains on dispositions

During 2014, Perpetual recorded gains of $42.9 million primarily related to the East Edson Agreements. Perpetual closed the East Edson Agreements for net cash proceeds of $47.0 million combined with $9.4 million in non-monetary deemed proceeds related to the carried farm-in investment of $70 million. Perpetual also recorded gains on the sale of a non-cash swap of undeveloped lands within West Central Alberta during the first quarter of 2014 and on the disposition of its non-core Mannville heavy oil properties which closed during the fourth quarter of 2014. Property dispositions during the same period in 2013 generated net cash proceeds of $79.0 million, resulting in gains on dispositions of $52.1 million relating to the Elmworth property disposition during the first quarter of 2013.

WGS LP income (loss) and dividends

For the year ended December 31, 2014, Perpetual recorded an expense of $3.2 million representing its share of net loss on its equity investment in WGS LP compared to income of $3.8 million for the same period in 2013. Losses in WGS LP in 2014 were primarily due to non-cash unrealized losses in relation to fair value adjustments recognized on WGS LP's gas storage obligation due to increased forward prices. There were no dividends declared by or received from WGS LP during 2014 (2013 – $2.4 million).

Funds flow

	2014		2013	
	($ thousands)	***($/boe)***	*($ thousands)*	*($/boe)*
Realized revenue[1]	**253,663**	**33.81**	208,522	30.56
Royalties[2]	**(32,024)**	**(4.27)**	(19,042)	(2.79)
Operating expenses	**(78,128)**	**(10.41)**	(75,414)	(11.05)
Transportation costs	**(12,684)**	**(1.69)**	(10,163)	(1.49)
Operating netback[1]	**130,827**	**17.44**	103,903	15.23
GOB revenue net of payments	**6,059**	**0.81**	8,905	1.30
Exploration and evaluation[3]	**(3,165)**	**(0.42)**	(3,269)	(0.48)
Cash G&A	**(22,371)**	**(2.98)**	(24,509)	(3.59)
Interest[3]	**(29,955)**	**(3.99)**	(28,932)	(4.24)
Dividends from WGS LP	**–**	**–**	2,370	0.35
Funds flow[1]	**81,395**	**10.86**	58,468	8.57

(1) See "Non-GAAP measures" in this MD&A.
(2) Includes $5.2 million in East Edson Gross Overriding Royalty payments in relation to the East Edson Agreements.
(3) Excludes non-cash items.

Funds flow increased 39 percent from 2013 to $81.4 million ($0.55 per share), as a result of increased production, stronger crude oil and natural gas prices, and higher operating netbacks in 2014.

Net income

	2014			2013
	($ thousands)	***($/boe)***	*($ thousands)*	*($/boe)*
Funds flow[1]	**81,395**	**10.86**	58,468	8.57
Unrealized gains on derivatives	**11,946**	**1.59**	1,783	0.26
Call option premiums received	**-**	**-**	(953)	(0.14)
Payments on financial obligation	**2,829**	**0.38**	-	-
Exploration and evaluation[2]	**(2,779)**	**(0.37)**	(3,994)	(0.59)
Compensation expense, non-cash	**(5,972)**	**(0.80)**	(3,974)	(0.58)
Gain on dispositions	**42,944**	**5.72**	52,143	7.64
Impairment reversal (write-down)	**(21,400)**	**(2.85)**	5,171	0.76
Depletion and depreciation	**(94,736)**	**(12.63)**	(92,877)	(13.61)
Financial items, non-cash	**(7,637)**	**(1.02)**	(9,566)	(1.40)
WGS LP net income (loss) and dividends	**(3,224)**	**(0.43)**	1,419	0.21
Net income	**3,366**	**0.45**	7,620	1.12

(1) See "Non-GAAP measures" in this MD&A.
(2) Includes non-cash exploration and evaluation expense from expired leases and geological and geophysical costs.

The Corporation recorded net income of $3.4 million ($0.45 per boe) for the year ended December 31, 2014 compared to net income of 7.6 million ($1.12 per boe) for the same period in 2013 primarily as a result of the increased funds flow combined with gains on dispositions and unrealized gains on derivatives in 2014.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except where noted)	**Q4 2014**	Q3 2014	Q2 2014	Q1 2014
Financial				
Oil and natural gas revenues	**62,562**	63,126	72,348	64,754
Funds flow[1]	**17,316**	20,831	25,864	17,384
Per share – basic	**0.12**	0.14	0.17	0.12
Net income (loss)	**(18,273)**	36,414	2,549	(17,324)
Per share – basic	**(0.12)**	0.24	0.02	(0.12)
– diluted[2]	**(0.12)**	0.23	0.02	(0.12)
Capital expenditures				
Exploration and development	**25,639**	46,583	12,251	31,340
Geological and geophysical	**379**	34	218	13
Acquisitions	**756**	–	91	151
Dispositions	**(21,351)**	(46,998)	(3,000)	–
Other	**84**	347	108	75
Net capital expenditures	**5,507**	(34)	9,668	31,579
Common shares (thousands)				
Weighted average – basic	**149,084**	149,574	148,835	148,448
Operating				
Daily average production				
Natural gas (MMcf/d)	**122.5**	97.8	97.8	92.1
Oil and NGL (bbl/d)	**3,262**	3,324	3,738	3,451
Total (boe/d)	**23,685**	19,640	20,053	18,794
Average prices				
Natural gas – before derivatives ($/Mcf)	**3.96**	4.35	4.95	4.90
Natural gas – including derivatives ($/Mcf)	**4.16**	4.35	4.66	4.35
Oil and NGL – before derivatives ($/bbl)	**59.77**	78.26	83.08	77.72
Oil and NGL – including derivatives ($/bbl)	**64.39**	75.10	74.65	72.06

(1) See "Non-GAAP measures" in this MD&A.
(2) Periods in which Perpetual has reported a net loss have an anti-dilutive impact on per share calculations resulting in per share amounts for basic and diluted reported as the same. Diluted per share amounts for periods where Perpetual has reported net income have been calculated based on the weighted average diluted shares of 157.6 million and 160.3 million for the second and the third quarters of 2014, respectively.

($ thousands, except where 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)	(13,745)	(6,833)	(4,566)	32,764
Per share – basic	(0.09)	(0.05)	(0.03)	0.22
– diluted(2)	(0.09)	(0.05)	(0.03)	0.21
Capital expenditures				
Exploration and development	24,537	22,325	9,861	38,682
Geological and geophysical	(19)	25	499	774
Acquisitions	418	532	5,433	1,752
Dispositions	(901)	(60)	(84)	(77,930)
Other	2	34	19,162	51
Net capital expenditures	24,037	22,856	34,871	(36,671)
Common shares (thousands)				
Weighted average - basic	148,489	148,382	148,015	147,672
Operating				
Daily average production				
Natural gas (MMcf/d)	90.3	85.3	91.9	88.6
Oil and NGL (bbl/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

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

(2) Periods in which Perpetual has reported a net loss have an anti-dilutive impact on per share calculations resulting in per share amounts for basic and diluted reported as the same. Diluted per share amounts for periods where Perpetual has reported net income have been calculated based on the weighted average diluted shares of 171.7 million for first quarter of 2013.

FOURTH QUARTER FINANCIAL AND OPERATING RESULTS

The Corporation continued its focus on liquids-rich natural gas development in the West Central district by drilling 11 (10.0 net) wells during the fourth quarter of 2014, including two (1.0 net) wells at West Edson and nine (9.0 net) wells at East Edson. The East Edson wells were drilled utilizing partner funds held in escrow pursuant to the East Edson Agreements. All of these new wells have now been brought on production after completion and tie in operations were finished in the first quarter of 2015. Total capital expenditures of $26.0 million were spent on fourth quarter capital projects, including development spending at East Edson and the successful start-up of waterflood projects at Mannville.

Perpetual's fourth quarter 2014 total production of 23,685 boe/d was 28 percent higher than the comparative fourth quarter of 2013 (18,559 boe/d) with new production from the East Edson drilling program more than offsetting natural declines.

Revenue increased 27 percent during the fourth quarter of 2014 compared to the same period in 2013 primarily due to higher natural gas production and increased gas prices offset by lower oil and NGL volumes and prices. Despite increased royalty expenses due to the East Edson GORR, higher operating expenses, and a reduction to GOB revenue, Perpetual's funds flow increased 33 percent to $17.3 million in the fourth quarter of 2014 compared to $13.0 million reported for the same period in 2013. A net loss of $18.3 million ($0.12 per share) was recorded for the fourth quarter of 2014.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Perpetual targets to maintain a strong capital base to maintain investor, creditor and market confidence, and to sustain the future development of the business. The Corporation strives to manage 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. Perpetual's capital structure includes share capital, bank debt, senior notes, convertible debentures and adjusted working capital. In order to manage its capital structure, the Corporation may from time to time issue shares or debt securities, enter into business transactions including the sale of assets and adjust its capital spending to manage current and projected debt levels.

To strengthen Perpetual's financial position, the following significant transactions were executed in 2014:

- Perpetual completed the monetization of its future GOB credits for net proceeds of $21.3 million. Proceeds were applied to reduce bank indebtedness.
- Perpetual sold a 50 percent royalty interest in current developed producing reserves in the East Edson area which included net cash proceeds of $47 million, consisting of $17 million of unrestricted cash that was applied to reduce bank indebtedness, with the remaining $30 million held in escrow for development spending in East Edson. At the end of 2014, $6.6 million remained in escrow. Concurrent with

the royalty disposition, Perpetual also entered into a farm-in agreement, whereby the partner contributed $70 million which was held in a separate escrow account to be used to fund development activities in East Edson. As at December 31, 2014, substantially all the partner escrow cash was spent with the remaining balance spent early in 2015.
- On November 7, 2014, Perpetual divested several non-core heavy oil properties in eastern Alberta for gross proceeds of $21.4 million.
- Perpetual issued $125 million in senior unsecured notes, which bear interest at 8.75 percent annually and mature on July 23, 2019. The net proceeds from this issuance were used to redeem all of Perpetual's outstanding 7.25% Debentures in cash for approximately $99.9 million on August 25, 2014. The remaining balance was initially applied to further reduce bank indebtedness and then utilized for the early redemption of $25.0 million of Perpetual's $59.9 million outstanding 7.0% Debentures on December 31, 2014. The remaining $34.9 million of the 7.0% Debentures mature on December 31, 2015.

The combined impact of these transactions has alleviated financial liquidity restraints through the repayment of the majority of the Corporation's 2015 debt repayment obligations. In addition, the infusion of cash from both Perpetual's and its partners' East Edson escrow accounts has allowed Perpetual to accelerate its development program which is expected to increase production in 2015. The result of these transactions have provided Perpetual increased flexibility as it reviews repayment options on the remaining outstanding 7.0% Debentures maturing on December 31, 2015.

Capital management

($ thousands, except as noted)	**December 31, 2014**	December 31, 2013
Bank debt	**–**	70,618
Senior notes, measured at principal amount	**275,000**	150,000
Convertible debentures, measured at principal amount	**34,878**	159,779
Adjusted working capital deficiency (surplus)(1)(2)	**21,867**	(3,417)
Net debt	**331,745**	376,980
Shares outstanding at end of period *(thousands)*	**150,077**	148,490
Market price at end of period *($/share)*	**1.14**	1.11
Market value of shares	**171,088**	164,824
Total capitalization(1)	**502,833**	541,804
Net debt as a percentage of total capitalization	**66.0**	69.6
Trailing twelve months funds flow(1)	**81,395**	58,468
Net debt to funds flow ratio(3)	**4.1**	6.4

(1) See "Non-GAAP measures" in this MD&A.
(2) Includes $6.6 million of restricted cash held in escrow but excludes $0.5 million of East Edson partner capital held in escrow at December 31, 2014.
(3) Net debt to funds flow is calculated based on trailing funds flow for the most recent four quarters.

The Corporation monitors capital based on the ratio of net debt to trailing twelve months ("TTM") funds flow. As at December 31, 2014, the Corporation's ratio of net debt to TTM funds flow had improved significantly, decreasing 36 percent from year end 2013, to 4.1 to 1 (December 31, 2013 – 6.4 to 1). This ratio is monitored continuously by the Corporation and the targeted range of net debt to TTM 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 part of the management of this ratio, the Corporation prepares annual capital expenditure budgets and monthly funds flow forecasts, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment, acquisition and development activities and general industry conditions. Capital spending budgets are approved by the Board of Directors.

At December 31, 2014, Perpetual had net debt of $331.7 million, down $45.3 million from December 31, 2013. The reduction in net debt reflected 2014 funds flow, combined with proceeds received from dispositions, Perpetual's escrow funds related to the East Edson Agreements and the monetization of GOB royalty credits, which, in total, exceeded 2014 capital expenditures with the excess funds being applied as an overall reduction to net debt.

Perpetual's adjusted working capital deficiency at December 31, 2014 was $21.9 million compared to a surplus of $3.4 million at December 31, 2013. The Corporation has an adjusted working capital deficiency as a result of increased accounts payables associated with increased capital spending during the fourth quarter of 2014. In addition, accounts payable includes $13.5 million of unapplied cash calls in relation to funds being drawn on the partner's escrow account to fund a portion of 2015 drilling activities in East Edson. The increase in payables is partially offset by increased cash and restricted cash received from the East Edson royalty disposition and additional East Edson partner cash calls.

Reconciliation of net debt *($ millions)*	
Net debt, December 31, 2013[(1)]	377.0
Capital expenditures[(2)]	117.0
Dispositions, net of acquisitions	(70.4)
Proceeds on GOB monetization	(21.3)
Funds flow[(1)]	(81.4)
Expenditures on decommissioning obligations	6.6
Issue fees on senior notes	2.7
Other	1.5
Net debt, December 31, 2014[(1)(3)]	**331.7**

(1) See "Non-GAAP measures" in this MD&A.
(2) Capital expenditures consist of exploration and development including geological and geophysical costs and corporate assets.
(3) Excludes $0.5 million of East Edson partner capital held in escrow at December 31, 2014.

Cash and bank indebtedness

At December 31, 2014, Perpetual had cash and cash equivalents of $11.5 million (December 31, 2013 – nil) and restricted cash of $6.6 million (December 31, 2013 – nil) representing Perpetual's escrow funds related to the East Edson Agreements. Perpetual was undrawn on its credit facility with outstanding letters of credit in the amount of $8.8 million. Comparatively, at December 31, 2013, the Corporation had $70.6 million drawn on the credit facility and $5.9 million of outstanding letters of credit.

The Corporation's credit facility is with a syndicate of Canadian chartered banks. On May 6, 2014, the Corporation's lenders completed their semi-annual review of the borrowing base under the credit facility. Total availability under the facility was increased to $130 million from $110 million which consisted of a demand loan of $115 million and a working capital facility of $15 million. On June 26, 2014, total availability under the credit facility was reduced to $120 million in conjunction with the monetization of the Corporation's GOB royalty credits. On July 23, 2014, in conjunction with the issuance of new senior notes, the Corporation's credit facility was further reduced from $120 million to $100 million to adjust for future interest payments that will be required pursuant to terms of the senior notes.

On November 5, 2014, the Corporation's lenders completed their next semi-annual review of the borrowing base. Total availability under the facility was increased to $105 million consisting of a demand loan of $90 million and a working capital facility of $15 million. The increase was due to the conversion of undeveloped reserves to developed producing reserves driven by the drilling activities at East Edson despite the monetization of additional GOB royalty credits and the sale of non-core Mannville heavy oil assets. The revolving feature of the facility expires on April 30, 2015 with a 184 day term to maturity should it not be extended. The next semi-annual redetermination of the Corporation's borrowing base will occur on or before April 30, 2015.

At December 31, 2014, the Corporation had covenants that require consolidated debt to TTM income before interest, taxes, depletion and depreciation and non-cash items ("Consolidated Debt Ratio") to be less than 4.0 to 1.0. 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. The credit facility also contains covenants that require consolidated senior debt to TTM income before interest, taxes, depletion and depreciation and non-cash items ("Consolidated Senior Debt Ratio") to be less than 3.0 to 1.0. 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, 2014.

On March 5, 2015, the Corporation's lenders agreed to revise financial covenants based on prevailing low commodity prices at the end of 2014 and uncertainty surrounding forecast commodity prices into 2016. The lenders have agreed to amend the financial covenants contained in the credit facility to:

- Waive the Consolidated Debt Ratio for the quarter ending June 30, 2015 for a period up to and including the quarter ending June 30, 2016.
- Provide for a financial covenant that requires TTM income before interest, taxes, depletion and depreciation and non-cash items to consolidated fixed charges ("Fixed Charges Ratio") of at least 1.45 to 1.0 beginning for the quarter ending June 30, 2015 up to and including the quarter ending June 30, 2016. Fixed charges is defined as the sum of interest on senior notes, convertible debentures, and bank indebtedness less the amortization of debt issuance costs.
- Revise the Consolidated Debt Ratio for the quarter ending September 30, 2016 such that the Corporation will be required to maintain a Consolidated Debt Ratio not exceeding 4.5 to 1.0.
- Reinstate the requirement to maintain a Consolidated Debt ratio not exceeding 4.0 to 1.0 beginning with the quarter ending December 31, 2016.

Advances under the credit facility are made in the form of Banker's Acceptances ("BA"), prime rate loans or letters of credit. 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.

The credit facility bears interest at its lenders' prime rate or BA rates, plus applicable margins and standby fees. The applicable margins range between 1.25 percent and 4.25 percent depending on the form of borrowing and changes in the Corporation's Consolidated Debt Ratio for the most recently completed reporting period.

Convertible debentures

At the beginning of 2014, the Corporation had outstanding $99.9 million of 7.25% Debentures maturing on January 31, 2015, as well as $59.9 million of 7.0% Debentures maturing on December 31, 2015.

The Corporation had the option to settle all or a portion of the outstanding 7.25% Debentures in cash or through the issuance of shares, with no penalty, by giving notice of such intent to debenture holders not more than 60 and not less than 30 days prior to the maturity date. On July 23, 2014, Perpetual gave notice to debenture holders that the 7.25% Debentures would be settled in cash with proceeds received from the $125 million senior unsecured notes. Settlement of the 7.25% Debentures occurred on August 25, 2014. Redemption of the total principal amount and accrued interest was funded from proceeds on the issuance of new senior notes.

The outstanding 7.0% Debentures may also be settled in cash or through the issuance of shares, with no penalty, on or after December 31, 2014, by giving notice of such intent to debenture holders not more than 60 and not less than 30 days prior to the maturity date. On December 31, 2014, Perpetual redeemed $25 million of the outstanding principle amount in cash. The redemption and accrued interest was funded primarily from proceeds received on the disposition of non-core heavy oil properties during the fourth quarter of 2014.

At December 31, 2014, $34.9 million of the Corporation's 7.0% Debentures remain outstanding as a short term liability. Management is evaluating repayment options including utilizing excess funds flow and bank indebtedness, asset dispositions, refinancing, or a combination thereof. There is no assurance that the Corporation will be able to raise additional capital to settle all or a portion of the outstanding 7.0% Debentures in cash, in which case, the Corporation would have the option to settle all or a portion with common shares. Additional information on the remaining 7.0% Debentures are as follows:

Principal issued ($ millions)	60.0
Principal outstanding ($ millions)	34.9
Trading symbol on the Toronto Stock Exchange	PMT.DB.E
Maturity date	December 31, 2015
Conversion price ($ per share)	7.00
Fair market value ($ millions)[1]	34.9

[1] Fair values of the 7.0% Debentures are calculated by multiplying the number of debentures outstanding at March 4, 2015 by the quoted market price per debenture at that date.

Senior notes

At December 31, 2014, Perpetual had $275 million of senior notes outstanding, including $125 million of senior notes issued during 2014, proceeds from which were used to redeem certain of the Corporation's outstanding convertible debentures. Additional information on the senior notes is as follows:

($ thousands, except where noted)	**Maturity date**	**Principal**	**Interest rate**	**December 31, 2014**	December 31, 2013
2011 senior notes[1]	March 15, 2018	150,000	8.75%	**148,223**	147,719
2014 senior notes[2]	July 23, 2019	125,000	8.75%	**122,467**	–
		275,000		**270,690**	147,719

[1] Issued March 15, 2011, interest payable semi-annually on September 15 and March 15 of each year.
[2] Issued July 23, 2014, interest payable semi-annually on January 23 and July 23 of each year.

The fair market value of the senior notes at March 4, 2015 was $238.3 million.

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 Corporation can redeem up to 35 percent of the principal amount of the senior notes at a premium to face value with proceeds from common share offerings up to three years prior to maturity. Within three years of maturity the Corporation can repay the senior notes at a premium to face value based on the date of repayment.

The senior notes have a cross-default provision with the Corporation's credit facility which require the Consolidated Debt Ratio and the Consolidated Senior Debt Ratio to be less than 4.0 to 1.0 and 3.0 to 1.0, respectively. The Corporation was in compliance with the lenders' covenants at December 31, 2014. The Corporation's lenders have agreed to amend the credit facility agreement for the period beginning with the quarter ended June 30, 2015 up to and including the quarter ended June 30, 2016 to remove the Consolidated Debt Ratio and replace it with the Fixed Charges Ratio. The Consolidated Debt Ratio requirement for the quarter ended September 30, 2016 will be 4.5 to 1.0. Subsequent to this the Consolidated Debt Ratio requirement will return to 4.0 to 1.0 beginning with the quarter ended December 31, 2016.

The senior notes indenture also contains restrictions on certain payments including dividends, retirement of subordinated debt and stock repurchases. The permitted amount of any restricted payment is limited to:

i) To the extent the Corporation's Consolidated Debt Ratio is less than 3.0 to 1.0, the sum of 50 percent of income before interest, taxes, depletion and depreciation and non-cash items from January 1, 2011 to the end of the most recently completed fiscal quarter plus 100 percent of the fair market value of any equity contributions made to the Corporation during that period less the sum of all restricted payments during that period; and

ii) To the extent the Corporation's Consolidated Debt Ratio is greater than or equal to 3.0 to 1.0 pro forma for the proposed restricted payment, $50 million plus 100 percent of the fair market value of any equity contributions made to the Corporation.

At December 31, 2014 the senior notes are presented net of $4.3 million in issue costs which are amortized using a weighted average effective interest rate of 9.2 percent.

Equity

Perpetual's total capitalization was $502.8 million at December 31, 2014. Net debt as a percentage of total capitalization was 66 percent, down from 70 percent at December 31, 2013. The decrease was driven by lower net debt levels resulting from proceeds on dispositions, GOB monetization and funds flow exceeding capital spending for the period.

Basic weighted average shares outstanding for the year ended December 31, 2014 totaled 149.1 million (2013 – 148.1 million). On March 5, 2015 there were 150.1 million shares outstanding.

2015 OUTLOOK

In 2015, Perpetual is focused on five strategic priorities:

- Grow greater Edson liquids-rich gas production, cash flow, inventory, reserves and value;
- Optimize value of Mannville heavy oil;
- Refine elements of production growth strategy for 2017 to 2020;
- Maximize value of shallow gas; and
- Reduce debt and improve debt/cash flow ratio.

In light of current weakness and uncertainty in commodity prices, Perpetual's Board of Directors has approved a first quarter capital expenditure budget of $45 million. Nearly $42 million will be directed to the drilling of six wells (4.5 net) in west central Alberta, with three (1.5 net) at West Edson and three (3.0 net) at East Edson, coupled with the East Edson plant construction activities. All heavy oil drilling has been deferred until oil prices recover, although $1.3 million will be expended on advancing the Mannville waterflood. Strategic spending at Panny to advance the LEAD pilot project has been reduced to include only capital required to drill two (2.0 net) observation wells associated with the pilot scheme, estimated at $1.2 million.

Capital activity for the remainder of the year will be assessed as the year progresses with the intention that spending will be largely funded from funds flow and available bank indebtedness. The reduction in drilling in first quarter 2015 will not materially impact 2015 gas production as the wells drilled to date have generally exceeded the type curves and provide the same production capability as originally budgeted. Further, variations in capital spending for the final three quarters of 2015 are not expected to materially affect average production or annual funds flow.

Perpetual has commodity price contracts in place for both crude oil and natural gas to protect a base level of cash flow. Natural gas contracts were entered into to provide downside protection on revenue, primarily through the summer months, with physical and financial contracts in place for 2015 on an average of close to 68,400 GJ/d at an average price of $2.63/GJ. Crude oil contracts for 2015 on 1,000 bbls/d include costless collars protecting a WTI floor price of Cdn$87.50/bbl with an average ceiling of Cdn$95.50/bbl, as well as financial contracts which fix the basis differential between WTI and Western Canadian Select trading hubs at an average of US$16.88/bbl.

Incorporating the assumptions and commodity price contracts outlined above, the following table shows Perpetual's estimated 2015 funds flow using various commodity prices:

Projected 2015 funds flow[(2)] (*$ millions*)

		AECO gas price ($/GJ)[(1)]				
		$2.50	**$3.00**	**$3.50**	**$4.00**	**$4.50**
WTI price (US$/bbl)[(1)]	**$45.00**	4.7	13.8	22.9	32.1	41.2
	$50.00	6.8	15.9	25.1	34.2	43.3
	$55.00	8.9	18.0	27.2	36.3	45.4
	$60.00	11.0	20.1	29.3	38.4	47.5
	$65.00	13.1	22.2	31.4	40.5	49.6

(1) The current settled and forward average AECO and WTI prices for 2015 as of March 4, 2015 were $2.69 per GJ and US$55.69 per bbl, respectively.
(2) Funds flow is a non-GAAP measures. Please refer to "Non-GAAP Measures" below.

On March 5, 2015, the Corporation's lenders agreed to revise financial covenants based on prevailing low commodity prices at the end of 2014 and uncertainty surrounding forecast commodity prices into 2016. Based on internal 2015 and 2016 financial and operating forecasts, Perpetual expects to be in compliance with the lender's new covenants.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

Perpetual has contractual agreements comprised of office lease costs and related sublease recoveries, as well as long-term commitments to utilize drilling rigs and pay for gas transportation on certain major pipeline systems in western Canada. As of December 31, 2014, the future minimum payments under these contractual agreements consisted of:

($ thousands)	**Drilling Commitments**	**Pipeline commitments**	**Operating lease commitments**
2015	3,533	9,560	1,712
2016	2,712	7,627	1,685
2017	1,416	5,868	1,621
2018	–	3,986	405
2019	–	3,986	–
Total	**7,661**	**31,027**	**5,423**

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; and
- maintaining strict environment, safety and health practices.

A complete discussion of risk factors is included in the Corporation's 2014 AIF available on the Corporation's website at www.perpetualenergyinc.com or on sedar 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, 2014, 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 filed or sent to securities regulatory authorities within the time periods specified under Canadian securities laws.

Management's annual report on internal controls over financial reporting

Management is responsible for establishing and maintaining adequate ICOFR, 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 IFRS.

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, 2014 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2014, the internal control over financial reporting was effective.

Changes to internal controls over financial reporting

There were no changes in the Corporation's internal control over financial reporting during the period beginning on January 1, 2014 and ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

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 2014 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, 2014.

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, 2014.

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 2014 to 2013 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 Riddell Rose

Susan L. Riddell Rose
President &
Chief Executive Officer

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

March 5, 2015

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, 2014 and December 31, 2013, the consolidated statements of income and comprehensive income, changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, 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, 2014 and December 31, 2013, and its consolidated financial performance and its consolidated cash flows for the years then ended, in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 5, 2015

PERPETUAL ENERGY INC.
Consolidated Statements of Financial Position

As at	December 31, 2014	December 31, 2013
(Cdn$ thousands)		
Assets		
Current assets		
Cash and cash equivalents	**$ 11,497**	$ –
Restricted cash (note 4)	**6,552**	–
Accounts receivable	**50,297**	36,099
Prepaid expenses and deposits	**1,635**	1,369
Derivatives (note 18)	**9,315**	326
	79,296	37,794
Long term Crown receivable (note 7)	**–**	10,997
Derivatives (note 18)	**–**	19
Property, plant and equipment (note 4)	**561,956**	576,954
Exploration and evaluation (note 5)	**84,227**	88,177
Equity-method investment (note 6)	**25,123**	28,347
Total assets	**$ 750,602**	$ 742,288
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 91,859**	$ 45,059
Derivatives (note 18)	**2,398**	6,468
Bank indebtedness (note 8)	**–**	70,618
Convertible debentures (notes 9 and 19)	**33,810**	–
Financial obligation (note 10)	**3,584**	–
Provisions (note 12)	**5,372**	8,011
	137,023	130,156
Derivatives (note 18)	**3,872**	2,778
Senior notes (note 11)	**270,690**	147,719
Convertible debentures (notes 9 and 19)	**–**	154,496
Financial obligation (note 10)	**11,806**	–
Provisions (note 12)	**220,928**	208,843
Total liabilities	**644,319**	643,992
Equity		
Share capital (note 13)	**1,258,840**	1,257,315
Shares held in trust (note 14)	**(1,387)**	–
Equity component of convertible debentures	**3,174**	13,971
Contributed surplus	**36,754**	21,474
Deficit	**(1,191,098)**	(1,194,464)
Total equity	**106,283**	98,296
Total liabilities and equity	**$ 750,602**	$ 742,288

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

PERPETUAL ENERGY INC.
Consolidated Statements of Income and Comprehensive Income

	Year Ended December 31	
	2014	2013
(Cdn$ thousands, except per share amounts)		
Revenue		
Oil and natural gas	**$ 262,790**	$ 201,294
Royalties	**(32,024)**	(19,042)
	230,766	182,252
Change in fair value of commodity price derivatives (note 18)	**2,819**	8,058
Gas over bitumen (note 3i)	**8,888**	8,905
	242,473	199,215
Expenses		
Production and operating	**78,128**	75,414
Transportation	**12,684**	10,163
Exploration and evaluation (note 5)	**5,944**	7,263
General and administrative	**28,343**	28,483
Gains on dispositions (notes 4)	**(42,944)**	(52,143)
Depletion and depreciation (note 4)	**94,736**	92,877
Impairment losses and (reversals) (note 4)	**21,400**	(5,171)
Income from operating activities	**44,182**	42,329
Finance expenses (note 16)	**(37,592)**	(38,498)
Share of net income (loss) of equity-method investment (note 6)	**(3,224)**	3,789
Net income and comprehensive income	**3,366**	7,620
Income per share (note 13)		
Basic and diluted	**$ 0.02**	$ 0.05

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

PERPETUAL ENERGY INC.
Consolidated Statements of Changes in Equity

	Share capital (thousands)	($thousands)	Shares held in trust	Equity component of convertible debentures	Contributed surplus	Deficit	Total equity
(Cdn$ thousands)							
Balance at December 31, 2013	148,490	$ 1,257,315	$ –	$ 13,971	$ 21,474	$ (1,194,464)	$ 98,296
Net income and comprehensive income	–	–	–	–	–	3,366	3,366
Common shares issued pursuant to share based compensation plans	1,587	1,544	–	–	(1,489)	–	55
Share based compensation expense (note 15)	–	–	–	–	5,972	–	5,972
Redemption of convertible debentures (note 9)	–	–	–	(10,797)	10,797	–	–
Change in shares held in trust (note 14)	–	(19)	(1,387)	–	–	–	(1,406)
Balance at December 31, 2014	**150,077**	**$ 1,258,840**	**$ (1,387)**	**$ 3,174**	**$ 36,754**	**$ (1,191,098)**	**$ 106,283**

	Share capital (thousands)	($thousands)	Shares held in trust	Equity component of convertible debentures	Contributed surplus	Deficit	Total equity
(Cdn$ thousands)							
Balance at December 31, 2012	147,455	$ 1,255,450	$ –	$ 13,988	$ 19,308	$ (1,202,084)	$ 86,662
Net income and comprehensive income	–	–	–	–	–	7,620	7,620
Common shares issued pursuant to share based compensation plans	1,035	1,865	–	–	(1,838)	–	27
Share based compensation expense (note 15)	–	–	–	–	3,974	–	3,974
Share based payment liability	–	–	–	–	13	–	13
Redemption of convertible debentures	–	–	–	(17)	17	–	–
Balance at December 31, 2013	148,490	$ 1,257,315	$ –	$ 13,971	$ 21,474	$ (1,194,464)	$ 98,296

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

PERPETUAL ENERGY INC.
Consolidated Statements of Cash Flows

(Cdn$ thousands)	Year Ended December 31 2014	2013
Cash flows from (used in) operating activities		
Net income	**$ 3,366**	$ 7,620
Adjustments to add (deduct) non-cash items:		
Depletion and depreciation	**94,736**	92,877
Exploration and evaluation (note 5)	**2,135**	2,715
Share based compensation expense	**5,972**	3,974
Change in fair value of commodity price derivatives (note 18)	**(11,946)**	(1,783)
Finance expenses	**7,637**	9,566
Share of net (income) loss of equity-method investment	**3,224**	(3,789)
Gains on dispositions	**(42,944)**	(52,143)
Impairment losses and (reversals)	**21,400**	(5,171)
Share of dividends from equity-method investment (note 6)	**–**	2,370
Call option premiums received	**–**	953
Long-term Crown receivable adjustments	**10,997**	(2,213)
Expenditures on decommissioning obligations (note 12)	**(6,633)**	(2,497)
Change in non-cash working capital (note 17)	**(5,862)**	(146)
Net cash from operating activities	**82,082**	52,333
Cash flows from (used in) financing activities		
Change in bank indebtedness	**(70,618)**	(7,356)
Repayment of convertible debentures (note 9)	**(124,903)**	(187)
Net proceeds on senior notes issuance (note 11)	**122,292**	–
Change in financial obligation (note 10)	**18,425**	–
Transactions with trustee (note 14)	**(1,406)**	–
Common shares issued	**55**	27
Change in non-cash working capital (note 17)	**1,527**	(20)
Net cash used in financing activities	**(54,628)**	(7,536)
Cash flows from (used in) investing activities		
Acquisitions	**(998)**	(8,135)
Capital expenditures	**(116,427)**	(95,525)
Proceeds on dispositions	**71,349**	78,975
Proceeds on sale of marketable securities	**–**	1,871
Increased interest in equity-method investment (note 6)	**–**	(19,129)
Change in non-cash working capital (note 17)	**30,119**	(2,854)
Net cash used in investing activities	**(15,957)**	(44,797)
Change in cash and cash equivalents	**11,497**	–
Cash and cash equivalents, beginning of year	**–**	–
Cash and cash equivalents, end of year	**$ 11,497**	$ –
Interest paid	**$ 28,443**	$ 29,220

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

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 shallow gas in Eastern Alberta, conventional heavy oil, 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. 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, 2015.

The consolidated financial statements have been prepared on a historical cost basis except for the hybrid financial obligation (note 10) and derivative financial instruments (note 18) 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.

a) 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.

b) 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) Identification of impairment indicators

Judgment is required to assess when significant indicators of impairment or reversals exist and whether calculation of the recoverable amount of an asset is necessary. Management considers internal and external sources of information that suggest the carrying amount of an asset is impaired, or in the case of a previously impaired asset, whether the carrying amount of the asset has been restored.

iii) 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 judgment 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.

iv) 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 judgment 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 property, plant and equipment referred to as oil and natural gas properties.

v) Joint arrangements

Judgment 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 judgment 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.

c) 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 natural gas liquids ("NGL" or "liquids") reserves in the calculation of depletion and also for value in use ("VIU") and fair value less costs of disposal ("FVLCD") 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, future commodity prices, 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 or review 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, liability specific discount rates and 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.

iv) Financial obligation

The hybrid financial obligation is measured at fair value on each reporting date. Fair value is the price that would be paid to exit the position as of the measurement date. The fair value of the financial obligation is estimated by discounting future cash payments based on the forecasted Alberta gas reference price multiplied by the contracted deemed volume. Changes in market pricing between period end and settlement of the hybrid financial obligation could have a material impact on financial results related to the financial obligation.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these annual consolidated financial statements, and have been applied consistently by the Corporation, 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 structured through a separate vehicle whereby joint control is established and the contractual arrangement provides the parties with rights to the net assets of WGS LP. Perpetual's investment in 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 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.

An impairment loss in respect of an equity-method accounted investee is measured by comparing the recoverable amount of the investment with its carrying amount. An impairment loss is recognized in profit or loss, and is reversed if there is a favorable change in the estimates used to determine the recoverable amount.

iv) Joint operations

Many of the Corporation's oil and natural gas activities involve jointly controlled operations which are not conducted through a separate vehicle. The consolidated financial statements include the Corporation's proportionate share of these jointly controlled assets, liabilities, revenues 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.

Financial instruments 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.

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

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.

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 designated 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 designated 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
Financial obligation	Financial liabilities	Fair value through profit or loss

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. The initial cost of property, plant and equipment includes the purchase price or construction costs, costs that are directly attributable to bringing the asset into commercial operations, the initial estimate of decommissioning costs, and borrowing costs for qualifying assets.

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 have 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 on 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 costs necessary to bring those reserves into production and future decommissioning costs. 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

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 are capitalized as E&E costs. 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 of disposal, 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 they are 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 FVLCD and its VIU. FVLCD 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 FVLCD 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 to reduce the carrying amount of assets in the unit (group of units) on a pro rata basis. Impairment losses are recognized in net income or loss.

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) Shares held in trust

The Corporation has a compensation program whereby employees may be entitled to receive shares of the Corporation purchased on the open market by a trustee controlled by Perpetual. Shares acquired and held by the trustee for the benefit of employees that have not yet been issued to employees are presented as a separate category of equity. The balance of shares held in trust represents the cumulative cost of shares held by the trustee. Upon the issuance of shares to the employee, the amount attributable to an employee is deducted from the balance of shares held in trust and transferred to share capital along with the associated compensation benefit recognized in contributed surplus.

h) Share based payments

Awards granted under share based payment plans and agreements are equity-settled and are measured at grant-date 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, or property, plant and equipment to the extent they are directly attributable, 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.

i) 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 non-current provision is determined using the estimated future cash flows discounted at a rate that reflects current market conditions and liability specific risks.

i) 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 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.

ii) 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.

j) 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.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements. Gas over bitumen adjustments are recognized as revenue to the extent that they offset gas Crown royalties otherwise payable in a given period.

k) 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.

l) 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**.**

m) Newly adopted accounting policies

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 has adopted IFRIC 21 in its financial statements for the annual period beginning January 1, 2014.

ii) IAS 32, "Financial Instruments: Presentation" was amended to provide further criteria on the legal right and intention to offset financial assets and financial liabilities. The Corporation has adopted the amended IAS 32 in its financial statements for the annual period beginning January 1, 2014.

Adoption of these standards and amendments has had no measurement or disclosure impact on the Corporation's consolidated financial statements.

n) 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) IFRS 11, "Interests in Joint Operations" was amended on May 6, 2014 to require the application of business combination accounting on acquisitions of interests in a joint operation that constitutes a business. The amendments apply prospectively for annual periods beginning on or after January 1, 2016.

ii) IFRS 9, "Financial Instruments" was issued on July 24, 2014 and introduces new requirements for the classification and measurement of financial assets. Under the new standard, financial assets are classified and measured based on the business model in which they are held and the characteristics of their contractual cash flows. The standard amends the impairment model by introducing a new 'expected credit loss' model for calculating impairment. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. The restatement of prior periods is not required and is only permitted if information is available without the use of hindsight.

Perpetual has not applied any of these new standards as of December 31, 2014. The Corporation is currently evaluating the extent of the impact that adoption will have on the consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT

	Oil and gas properties	Corporate assets	Total
Cost			
December 31, 2012	$ 2,473,440	$ 6,287	$ 2,479,727
Additions	93,180	120	93,300
Change in decommissioning obligations estimates (note 12)	2,182	–	2,182
Transfers from exploration and evaluation (note 5)	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
Additions	114,975	614	115,589
Non-monetary additions	9,362	–	9,362
Change in decommissioning obligations estimates (note 12)	8,324	–	8,324
Transfers from exploration and evaluation (note 5)	5,495	–	5,495
Acquisitions	826	–	826
Dispositions	(65,585)	–	(65,585)
December 31, 2014	**$ 2,633,900**	**$ 7,021**	**$ 2,640,921**
Accumulated depletion, depreciation and impairment losses			
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)
Depletion and depreciation	(94,391)	(345)	(94,736)
Dispositions	27,127	–	27,127
Impairment	(26,400)	–	(26,400)
Impairment reversal	5,000	–	5,000
December 31, 2014	**$ (2,072,642)**	**$ (6,323)**	**$ (2,078,965)**
Carrying amount			
December 31, 2013	$ 576,525	$ 429	$ 576,954
December 31, 2014	**$ 561,258**	**$ 698**	**$ 561,956**

At December 31, 2014, property, plant and equipment included $35.0 million (December 31, 2013 – $7.9 million) of costs currently not subject to depletion and $19.6 million (December 31, 2013 – $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.

On July 16, 2014 the Corporation closed an arrangement with a partner which resulted in the dispositions of a portion of lands in the East Edson area of the Corporation's West Central CGU. Net proceeds consisted of $17.0 million of unrestricted cash and $30 million held in escrow to be used to drill, complete and tie-in approximately five wells in the East Edson property prior to December 31, 2015. As at December 31, 2014, the amount held in Perpetual's escrow account was $6.6 million. The Corporation also recognized $9.4 million in deemed proceeds related to the partner's $70 million farm-in investment which is committed to the drilling, completion and tie-in of approximately 14 wells pursuant to a farm-in agreement. The net book value of assets disposed included $21.7 million property, plant, and equipment and $1.2 million of exploration and evaluation assets.

In conjunction with the arrangement, the Corporation has additional capital commitments totaling $60 million following spending of the $70 million farm-in investment by the partner. This includes $30 million to drill, complete and tie-in approximately six more wells prior to December 31, 2022 and an estimated $30 million for the construction of a new gas plant expected to be completed and operational by the beginning of the third quarter of 2015.

During the year ended December 31, 2014, the Corporation disposed of oil and natural gas properties for net proceeds of $71.3 million (2013 - $79.0 million). Gains on dispositions totaling $42.9 million (2013 - $52.1 million) were recorded in net income.

a) Impairments and reversals

For the year ended December 31, 2014, Perpetual conducted an assessment of impairment indicators for the Corporation's CGUs. In performing the review management determined that the recent decline in commodity pricing and the impact these price declines have on the economic performance of the Corporation's CGUs justified calculation of the recoverable amount of all CGUs. The recoverable amount of the CGUs was based on the higher of VIU and FVLCD. The impairment test was completed using estimates of VIU for each CGU.

VIU was determined based on the net present value of cash flows from the CGUs oil, natural gas, and NGL reserves using estimates of total proved plus probable reserves evaluated or reviewed by Perpetual's independent reserves evaluators along with the associated year-end commodity price forecast, and an estimate of market discount rates between 10 and 15 percent to consider risks specific to the asset. At December 31, 2014, the Corporation determined that:

i) the carrying amount of the Birchwavy East CGU exceeded its recoverable amount, accordingly, an impairment charge of $26.4 million is included in net income for the year related to oil and natural gas assets in the Birchwavy East CGU.

ii) the recoverable amount of the Birchwavy West CGU exceeded its carrying amount by $5.0 million, accordingly, a reversal of $5.0 million was recognized in net income representing a partial reversal of previously recorded impairments. This reversal is a result of the underlying assets demonstrating sustainable operational performance since the last calculation of the recoverable amount.

The independent reserve evaluator's commodity price estimates were used in the VIU calculations as at December 31, 2014:

Year	WTI Crude Oil (US$/bbl)	USD/CDN exchange rate (US$/Cdn$)	Alberta heavy crude oil (Cdn$/bbl)	AECO natural gas (Cdn$/mmbtu)
2015	65.00	0.86	51.10	3.50
2016	75.00	0.86	62.00	4.00
2017	80.00	0.86	66.20	4.25
2018	84.90	0.86	70.50	4.50
2019	89.30	0.86	74.20	4.70
2020	93.80	0.86	78.00	5.00
2021	95.70	0.86	79.60	5.30
2022	97.60	0.86	81.20	5.50
2023	99.60	0.86	82.80	5.70
2024	101.60	0.86	84.60	5.90
2025	103.60	0.86	86.20	6.00
2026	105.70	0.86	87.90	6.10
2027	107.80	0.86	89.70	6.25
2028	110.00	0.86	91.50	6.35
2029	112.20	0.86	93.30	6.50

Escalate 2.0 percent per year thereafter

For the year ended December 31, 2013, the Corporation identified indicators of a reversal in the West Central CGU as a result of positive reserve revisions related to the strong economic performance of Perpetual's wells located the CGU. Using VIU, Perpetual determined that the recoverable amount of the CGU exceed the total of the previous impairment charge less any subsequent depletion, accordingly, income for the year ended December 31, 2013 includes a reversal of $5.2 million.

5. EXPLORATION AND EVALUATION

	2014	2013
Balance, beginning of year	**$ 88,177**	$ 80,494
Additions	**3,990**	5,617
Non-monetary additions	**6,000**	–
Acquisitions	**172**	7,400
Dispositions	**(6,482)**	(1,193)
Transfers to property, plant and equipment	**(5,495)**	(1,426)
Non-cash exploration and evaluation expense	**(2,135)**	(2,715)
Balance, end of year	**$ 84,227**	$ 88,177

During the year ended December 31, 2014, $3.8 million (2013 – $4.5 million) in costs were charged directly to E&E expense in net loss.

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. During the year ended December 31, 2013, Perpetual exercised an 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. As part of the sale Perpetual continues to provide management and operational services to WGS LP for an annual fee.

For the year ended December 31, 2014, transactions between Perpetual and WGS LP during the year totaled $1.7 million (December 31, 2013 - $2.0 million) consisting primarily of revenue earned related to the management services agreement. No dividends were declared by WGS LP during the year (2013 - $2.4 million).

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

As at	**December 31, 2014**	December 31, 2013
Current assets	**$ 676**	$ 2,925
Non-current assets	**119,128**	119,619
Total assets	**119,804**	122,544
Current liabilities[1]	**13,164**	739
Non-current liabilities[2]	**27,177**	31,596
Total liabilities	**40,341**	32,335
Net assets	**79,463**	90,209
Corporation's share of net assets	**23,839**	27,063
Adjustments on acquisition of interest in WGS LP	**1,284**	1,284
Equity-method investment	**$ 25,123**	$ 28,347

(1) Includes current bank indebtedness of $11.4 million (December 31, 2013 – nil).

(2) Includes long term bank indebtedness of nil (December 31, 2013 – $7.9 million).

For the year ended	**December 31, 2014**	December 31, 2013
Revenue	**$ 3,827**	$ 16,864
Depreciation	**(3,421)**	(3,564)
Other expenses	**(8,626)**	(2,609)
Unrealized gain (loss) on gas storage obligation derivative	**(2,527)**	4,920
Net income (loss)	**(10,747)**	15,611
Share of net income (loss) of equity-method investment	**$ (3,224)**	$ 3,789

7. LONG TERM CROWN RECEIVABLE

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, 2014, Perpetual had accumulated royalty adjustments on operated facilities in excess of the Corporation's accumulated Crown royalties payable totaling $4.0 million (December 31, 2013 - $18.1 million). The total amount is included in current accounts receivable at December 31, 2014 as the Corporation expects to recover this amount against Crown royalties otherwise payable in the next twelve months. At December 31, 2013 $7.1 million was included in current accounts receivable with the remaining $11.0 million recorded as long term Crown receivable as the Corporation expected to recover the amounts against Crown royalties payable over a period of time beyond the next year.

8. BANK INDEBTEDNESS

The Corporation's credit facility is with a syndicate of Canadian chartered banks. As part of the lender's semi-annual review of the borrowing base, on May 6, 2014 total availability under the facility was increased to $130 million from $110 million which consisted of a demand loan of $115 million and a working capital facility of $15 million. On June 26, 2014, total availability under the credit facility was reduced to $120 million in conjunction with the monetization of the Corporation's gas over bitumen royalty credits (see note 10). On July 23, 2014, in conjunction with the issuance of new senior notes, the Corporation's credit facility was further reduced from $120 million to $100 million to adjust for future interest payments that will be required pursuant to terms of the senior notes (see note 11).

On November 5, 2014, the Corporation's lenders completed their semi-annual review of the borrowing base. Total availability under the under the facility was increased to $105 million consisting of a demand loan of $90 million and a working capital facility of $15 million. The revolving feature of the facility expires on April 30, 2015 with a 184 day term to maturity should it not be extended. The next semi-annual redetermination of the Corporation's borrowing base will occur on or before April 30, 2015.

At December 31, 2014, the Corporation had covenants that require consolidated debt to trailing twelve month income before interest, taxes, depletion and depreciation and non-cash items ("Consolidated Debt Ratio") to be less than 4.0 to 1.0. 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. The credit facility also contains covenants that require consolidated senior debt to trailing twelve month income before interest, taxes, depletion and depreciation and non-cash items ("Consolidated Senior Debt Ratio") to be less than 3.0 to 1.0. 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, 2014.

On March 5, 2015, the Corporation's lenders agreed to revise financial covenants based on prevailing low commodity prices at the end of 2014 and uncertainty surrounding forecasted commodity prices into 2016. The lenders have agreed to amend the financial covenants contained in the credit facility to:

i) Waive the Consolidated Debt Ratio for the quarter ending June 30, 2015 for a period up to and including the quarter ending June 30, 2016.

ii) Provide for a financial covenant that requires trailing twelve month income before interest, taxes, depletion and depreciation and non-cash items to consolidated fixed charges ("Fixed Charges Ratio") of at least 1.45 to 1.0 beginning for the quarter ending June 30, 2015 up to and including the quarter ending June 30, 2016. Fixed charges is defined as the sum of interest on senior notes, convertible debentures, and bank indebtedness less the amortization of debt issuance costs.

iii) Revise the Consolidated Debt Ratio for the quarter ending September 30, 2016 such that the Corporation will be required to maintain a Consolidated Debt Ratio not exceeding 4.5 to 1.0.

iv) Reinstate the requirement to maintain a Consolidated Debt ratio not exceeding 4.0 to 1.0 beginning with the quarter ending December 31, 2016.

Advances under the credit facility are made in the form of Banker's Acceptances ("BA"), prime rate loans or letters of credit. The Corporation has outstanding letters of credit in the amount of $8.8 million (December 31, 2013 – $5.9 million) and no BA's or prime rate loans outstanding at December 31, 2014. 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.

The credit facility bears interest at its lenders' prime rate or BA rates, plus applicable margins and standby fees. The applicable margins range between 1.25% and 4.25% depending on the form of borrowing and changes in the Corporation's Consolidated Debt Ratio for the most recently completed reporting period.

9. CONVERTIBLE DEBENTURES

On August 25, 2014, the Corporation redeemed all of the outstanding 7.25% Convertible Debentures. Redemption of the total principal amount of $99.9 million and accrued interest of $0.5 million was funded from proceeds on the issuance of new senior notes (see note 11). Interest expense for the period includes a $0.2 million loss on redemption related to unamortized original issue discount and unamortized debt issuance costs.

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 and senior notes. 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. On December 31, 2014 the Corporation redeemed $25.0 million of the outstanding principal of the 7.00% Convertible Debentures. Finance expense for the period includes a $0.8 million loss on redemption related to the unamortized original issue discount and unamortized debt issuance costs.

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	7.25%	7.00%	Total
Trading symbol (TSX)	**PMT.DB.D**	**PMT.DB.E**	
Carrying amount			
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
Accretion	707	1,077	1,784
Amortization of debenture issue fees	339	579	918
Redemptions	(99,154)	(24,234)	(123,388)
Balance, December 31, 2014	**$ –**	**$ 33,810**	**$ 33,810**
Market Value			
December 31, 2013	$ 97,903	$ 57,333	$ 155,236
December 31, 2014	**$ –**	**$ 35,052**	**$ 35,052**
Principal amount outstanding			
December 31, 2013	$ 99,901	$ 59,878	$ 159,779
December 31, 2014	**$ –**	**$ 34,878**	**$ 34,878**

10. FINANCIAL OBLIGATION

	December 31, 2014
Balance, beginning of year	**–**
Additions	**$ 21,254**
Payments	**(2,829)**
Change in fair value of financial obligation	**(3,035)**
Balance, end of year	**$ 15,390**
Financial obligation – current	**$ 3,584**
Financial obligation – non-current	**11,806**
	$ 15,390

During 2014, the Corporation entered into agreements whereby the Corporation received cash proceeds of $21.3 million in exchange for an obligation to make a monthly cash payment equivalent to a portion of the Corporation's monthly GOB Royalty Adjustment entitlements until final expiries in June 2021. Monthly payments under the arrangement are due on the 25th day following the entitlement month.

At the inception of the arrangements, the estimated future payments were determined using the same formula as the Corporation's monthly GOB Royalty Adjustment entitlements under the Alberta Natural Gas Royalty Regulation based on a January 1, 2014 forecast for the Alberta gas reference price ("base cash payment"). In the event that the actual Alberta gas reference price for a month causes the actual monthly cash payment under the arrangement to differ from the base cash payment, the Corporation is required to (a) pay 65 percent of any increase from the base cash payment, or (b) deduct 100 percent of any decrease from the base cash payment. Security for the financial obligation is provided by an interest in certain lands of the Corporation and by the Corporation's entitlement to future GOB Royalty Adjustments.

This financial obligation is a hybrid financial instrument comprising of a debt host with an embedded derivative related to indexation of the future cash payments to changes in the future Alberta gas reference price. The Corporation has designated the financial obligation as a financial liability which is measured at fair value through profit and loss. For the year ended December 31, 2014, an unrealized gain of $3.0 million is included in finance expense related to the change in fair value of the financial obligation. See note 18 for a description of the valuation methodology used to estimate the fair value of the financial obligation.

As at December 31, 2014, if future natural gas prices changed by $0.25 per GJ with all other variables held constant, the fair value of the financial obligation and after tax net income for the period would change by $1.3 million. Fair value sensitivity is based on published forward AECO prices.

11. SENIOR NOTES

				Carrying value	
	Maturity date	**Principal**	**Interest rate**	**December 31, 2014**	December 31, 2013
2011 senior notes(1)	March 15, 2018	150,000	8.75%	**148,223**	147,719
2014 senior notes(2)	July 23, 2019	125,000	8.75%	**122,467**	–
		275,000		**270,690**	147,719

(1) Issued March 15, 2011, interest payable semi-annually on September 15 and March 15 of each year.
(2) Issued July 23, 2014, interest payable semi-annually on January 23 and July 23 of each year.

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 Corporation can redeem up to 35 percent of the principal amount of the senior notes at a premium to face value with proceeds from common share offerings up to three years prior to maturity. Within three years of maturity the Corporation can repay the senior notes at a premium to face value based on the date of repayment.

The senior notes have a cross-default provision with the Corporation's credit facility which require the Consolidated Debt Ratio and the Consolidated Senior Debt Ratio to be less than 4.0 to 1.0 and 3.0 to 1.0, respectively. The Corporation was in compliance with the lenders' covenants at December 31, 2014. The Corporation's lenders have agreed to amend the credit facility agreement for the period beginning with the quarter ended June 30, 2015 up to and including the quarter ended June 30, 2016 to remove the Consolidated Debt Ratio and replace it with the Fixed Charges Ratio. The Consolidated Debt Ratio requirement for the quarter ended September 30, 2016 will be 4.5 to 1.0. Subsequent to this the Consolidated Debt Ratio requirement will return to 4.0 to 1.0 beginning with the quarter ended December 31, 2016 (see note 8).

The senior notes indenture also contains restrictions on certain payments including dividends, retirement of subordinated debt and stock repurchases. The permitted amount of any restricted payment is limited to:

i) To the extent the Corporation's Consolidated Debt Ratio is less than 3.0 to 1.0, the sum of 50 percent of income before interest, taxes, depletion and depreciation and non-cash items from January 1, 2011 to the end of the most recently completed fiscal quarter plus 100 percent of the fair market value of any equity contributions made to the Corporation during that period less the sum of all restricted payments during that period.

ii) To the extent the Corporation's Consolidated Debt Ratio is greater than or equal to 3.0 to 1.0 pro forma for the proposed restricted payment, $50 million plus 100 percent of the fair market value of any equity contributions made to the Corporation.

At December 31, 2014 the senior notes are presented net of $4.3 million in issue costs which are amortized using a weighted average effective interest rate of 9.2 percent.

12. PROVISIONS

A reconciliation of provisions is provided below:

	2014	2013
Decommissioning obligations, beginning of year	**$ 213,906**	$ 206,379
Obligations acquired	**85**	73
Obligations incurred	**3,067**	3,392
Obligations disposed	**(1,173)**	(62)
Change in risk free rate	**14,343**	(12,574)
Change in estimates	**(6,019)**	14,756
Obligations settled	**(6,633)**	(2,497)
Accretion	**5,400**	4,439
Decommissioning obligations, end of year	**222,976**	213,906
Gas over bitumen obligation	**3,324**	2,948
Balance, end of year	**$ 226,300**	$ 216,854
Provisions – current	**5,372**	8,011
Provisions – non-current	**220,928**	208,843
	$ 226,300	$ 216,854

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 future costs and the estimated timing of costs to be incurred in future years.

At December 31, 2014, the Corporation estimated the net present value of its total decommissioning obligations to be $223.0 million (December 31, 2013 – $213.9 million) based on an undiscounted total future liability of $239.2 (December 31, 2013 – $236.8 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, 2014, the Corporation used a weighted average risk free rate of 1.98 percent (December 31, 2013 – 2.41 percent) to calculate the present value of the decommissioning obligation.

b) Gas over bitumen obligation

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, 2014, the Corporation estimated the net present value of its total gas over bitumen obligation to be $3.3 million (December 31, 2013 - $2.9 million) based on undiscounted total future repayments of $10.8 million (December 31, 2013 - $10.8 million). The majority of these repayments are expected to occur between 2020 and 2032. At December 31, 2014, the Corporation used a liability specific discount rate of 15.0 percent (December 31, 2013 – 15.0 percent) to calculate the present value of the provision.

For the year ended December 31, 2014, the Corporation recognized accretion of $0.4 million (2013 – nil) and a change in estimate of $0.1 million (2013 - $0.2 million) related to the gas over bitumen obligation in finance expense (note 16).

13. SHARE CAPITAL

a) Authorized

Authorized capital consists of an unlimited number of common shares.

b) Per share information

	Year ended December 31, **2014**	2013
(thousands, except per share amounts)		
Net income – basic	**$ 3,366**	$ 7,620
Effect of dilutive securities	**–**	–
Net income – diluted	**$ 3,366**	$ 7,620
Weighted average shares		
Issued common shares	**149,371**	148,144
Effect of shares held in trust	**(287)**	–
Weighted average common shares outstanding – basic	**149,084**	148,144
Effect of dilutive securities	**7,521**	2,098
Weighted average common shares outstanding – diluted	**156,605**	150,242
Income per share - basic and diluted	**$ 0.02**	$ 0.05

In computing per share amounts for the year ended December 31, 2014, 0.8 million potentially issuable common shares through the share based compensation plans (2013 – 1.6 million) and 17.2 million potentially issuable common shares through the convertible debentures (2013- 21.9 million) were excluded because they were anti-dilutive.

14. SHARES HELD IN TRUST

	December 31, 2014	
	Shares *(thousands)*	**Amount *($ thousands)***
Balance, beginning of year	**–**	**–**
Shares purchased and held in trust	**989**	**$ 1,406**
Disbursements to employees	**(11)**	**(19)**
Balance, end of year	**978**	**$ 1,387**

The Corporation has compensation agreements in place with employees whereby they may be entitled to receive shares of the Corporation purchased on the open market by a trustee. The balance of shares held in trust represents the cumulative cost of shares held by the trustee for the benefit of employees that have not yet been issued to employees.

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, number 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. At December 31, 2014, the Corporation had 15.0 million (2013 – 14.8 million) shares reserved for issuance under the Share Option and Restricted Right Plan, representing ten percent of total common shares outstanding.

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, 2014, the Corporation recorded $1.3 million in share based compensation expense related to Share Options (2013 – $1.8 million), with no cash payments made in 2014 (2013 – nil).

The Corporation used the trinomial option pricing model to calculate the estimated fair value of the outstanding Share Options. The following assumptions were used to arrive at the estimate of fair value as at the date of grant:

	2014	2013
Dividend yield (%)	**0.0**	0.0
Forfeiture rate (%)	**15.1**	12.0
Expected volatility (%)	**53.1**	48.0 – 52.1
Risk-free interest rate (%)	**1.3**	1.1 – 1.6
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	**$ 0.72**	$ 0.38

The following tables summarize information about Share Options outstanding at December 31, 2014:

	2014		2013	
	Average Exercise Price	**Share Options**	Average Exercise Price	Share Options
(thousands, except per share amounts)				
Balance, beginning of year	**$ 1.20**	**11,201**	$ 1.32	9,177
Granted	**2.06**	**2,200**	1.12	2,665
Exercised	**0.81**	**(343)**	0.69	(104)
Cancelled/forfeited	**1.19**	**(133)**	6.34	(171)
Expired	**4.23**	**(106)**	1.51	(366)
Balance, end of year	**$ 1.33**	**12,819**	$ 1.20	11,201

	Options Outstanding			**Options Exercisable**	
Range of Exercise Prices	**Number of Share Options (thousands)**	**Average Contractual Life (years)**	**Weighted Average Exercise Price**	**Number of Share Options (thousands)**	**Weighted Average Exercise Price**
$0.62 to $0.83	1,015	1.20	$ 0.62	569	$ 0.62
$0.84 to $1.07	4,968	1.47	1.03	3,253	1.03
$1.08 to $1.15	2,445	2.54	1.11	815	1.11
$1.16 to $1.66	1,449	1.01	1.25	1,360	1.26
$1.67 to $3.59	2,942	3.00	2.31	568	3.07
Total	**12,819**	**1.95**	**$ 1.33**	**6,565**	**$ 1.23**

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, 2014, $0.1 million in share based compensation expense was recorded in respect of Restricted Rights (2013 – $0.6 million).

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

	2014	2013
(thousands)		
Balance, beginning of year	**1,311**	2,246
Granted	**740**	200
Exercised	**(1,369)**	(988)
Forfeited	**(64)**	(147)
Balance, end of year	**618**	1,311

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. 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, 2014, the Corporation had 2.3 million Performance Share Rights issued and outstanding under the Performance Share Rights Plan (December 31, 2013 – 2.3 million).

For the year ended December 31, 2014, $2.6 million in share based compensation expense was recorded in respect of the Performance Share Rights granted (2013 – $1.2 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. The shares purchased by the Trustee are reported as shares held in trust (note 14).

At December 31, 2014, the Corporation had 2.5 million of these awards issued and outstanding (2013 – 1.2 million).

For the year ended December 31, 2014, $0.4 million in share based compensation expense was recorded in respect of the awards (2013 – $0.1 million).

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, 2014, the Corporation had 2.8 million of these awards issued and outstanding (2013 – 1.8 million).

For the year ended December 31, 2014, $1.6 million in share based compensation expense was recorded in respect of the compensation awards granted (2013 – $0.3 million).

16. FINANCE EXPENSE

The components of finance expense are as follows:

	Year ended December 31	
	2014	2013
Interest on senior notes[1]	**$ (18,350)**	$ (13,667)
Interest on convertible debentures[2]	**(13,128)**	(14,434)
Interest on bank indebtedness	**(3,373)**	(4,381)
Accretion on decommissioning obligations (note 12)	**(5,400)**	(4,439)
Accretion on GOB obligation (note 12)	**(442)**	–
Change in estimate on GOB obligation (note 12)	**66**	(211)
Change in fair value of financial obligation (note 10)	**3,035**	–
Loss on marketable securities	**–**	(92)
Loss on call option	**–**	(1,274)
Finance expenses recognized in net income or loss	**$ (37,592)**	$ (38,498)

(1) Includes $0.7 million (2013 - $0.5 million) of amortization of debt issuance costs for the year ended December 31, 2014.
(2) Includes $0.9 million (2013 - $1.0 million) of amortization of debt issuance costs for the year ended December 31, 2014.

17. NON-CASH WORKING CAPITAL INFORMATION

	Year ended December 31,	
	2014	2013
Restricted cash	**$ (6,552)**	$ –
Accounts receivable	**(14,198)**	(2,312)
Prepaid expenses and deposits	**(266)**	1,559
Accounts payable and accrued liabilities	**46,800**	(2,267)
Change in non-cash working capital	**$ 25,784**	$ (3,020)

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

	Year ended December 31, **2014**	2013
Operating	**$ (5,862)**	$ (146)
Financing	**1,527**	(20)
Investing	**30,119**	(2,854)
Change in non-cash working capital	**$ 25,784**	$ (3,020)

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 derivatives by engaging in risk management transactions with counterparties with investment grade credit ratings, and periodically monitoring the changes in such credit ratings.

During the year ended December 31, 2014, 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 cash and cash equivalents, accounts receivable and fair value of derivative assets represents the Corporation's maximum credit exposure. The Corporation's allowance for doubtful accounts as at December 31, 2014 is $0.7 million (December 31, 2013 – $0.6 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 $1.3 million as at December 31, 2014 (December 31, 2013 – $1.7 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, 2014:

Contractual repayments of financial liabilities	**Total**	**2015**	**2016**	**2017-2019**	**Thereafter**
Accounts payable and accrued liabilities	**$ 91,859**	$ 91,859	$ –	$ –	$ –
Derivatives	**6,270**	2,398	3,872	–	–
Convertible debentures – principal[1]	**34,878**	34,878	–	–	–
Senior notes – principal	**275,000**	–	–	275,000	–
Financial obligation	**15,390**	3,584	3,154	7,454	1,198
Total	**$ 423,397**	$ 132,719	$ 7,026	$ 282,454	$ 1,198

(1) 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 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 economic risk management are as follows:

Restrictive policy	**Contract type**	**Limit**
Internal Risk Management Policy[1]	Financial or forward physical oil or natural gas liquids-based volumes	80 percent of the average forecast future oil and condensate production volume after royalties
Internal Risk Management Policy[1]	Financial or forward physical natural gas-based volumes	80 percent of the average forecast future natural gas production volumes after royalties
Credit facility agreement	Financial or forward physical oil or natural gas liquids-based volumes	75 percent of forecasted oil and natural gas liquids production volumes for the upcoming fiscal quarter after royalties
Credit facility agreement	Financial or forward natural gas-based volumes	75 percent of forecasted natural gas production volumes for the upcoming fiscal quarter after royalties

(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, 2014, 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 losses on commodity price derivatives recognized in net income for the year ended December 31, 2014 were $9.1 million (2013 – gains of $6.3 million). The realized losses on commodity price derivatives for the year ended December 31, 2014, included gains of $0.4 million in respect of the settlement of contracts prior to maturity (2013 – $0.9 million).

Natural gas contracts

At December 31, 2014, the Corporation had entered into financial and forward natural gas sales arrangements at AECO as follows:

Term	Perpetual sold/bought	Volumes at AECO (GJ/d)	Price ($/GJ)	Term
January 2015 – March 2015	sold	10,000	4.23	Financial
January 2015	bought	(10,000)	3.35	Physical

Oil contracts

At December 31, 2014 the Corporation had entered into the following costless collar oil sales arrangements which settle in Cdn$:

Term	Volumes at WTI (bbl/d)	Floor price (Cdn$/bbl)	Ceiling price (Cdn$/bbl)	Type of contract
January 2015 – December 2015	500	87.50	95.25	Collar
January 2015 – December 2015	500	87.50	95.75	Collar

At December 31, 2014, 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.

Term	Perpetual sold/bought	Volumes at WTI-WCS (bbl/d)	Differential ($USD/bbl)	Type of contract
January 2015 – December 2015	sold	1,000	(16.88)	Financial

Financial Asian call oil sales arrangements whereby the Corporation's counterparty has the right to settle specified volumes of oil at specified prices in the future periods:

Term	Perpetual sold/bought	Volumes at WTI (bbl/d)	Average price (US$/bbl)	Type of contract
January 2016 – December 2016(1)	sold	500	106.00	Asian call
January 2016 – December 2016(2)	sold	1,000	104.25	Asian call

(1) If the monthly average WTI settles above US$106.00/bbl for any month Perpetual receives a price of US$97.00/bbl for that month.
(2) If the monthly average WTI settles above US$104.25/bbl for any month Perpetual receives a price of US$95.40/bbl for that month.

Foreign exchange contracts

At December 31, 2014, the Corporation had entered into the following $USD forward sales arrangement:

Term	Perpetual sold/bought	Notional US$/month	Exchange rate (Cdn$/US$)	Type of contract
January 2015 – June 2015(1)	sold	1,000,000	1.10	Financial

(1) The Corporation receives $1,000 each day during the month that the daily exchange rate is between 1.00 and 1.10. If the average monthly exchange rate is greater than 1.10 the Corporation pays US$1,000,000 multiplied by the difference between the average monthly exchange rate and 1.10. No settlement occurs between the Corporation and the counterparty if the average monthly exchange rate settles below 1.00.

At December 31, 2014, the Corporation had entered into the following $USD forward sales arrangement:

Term	Notional floor US$/ month	Notional ceiling US$/ month	Exchange rate floor (Cdn$/US$)	Exchange rate ceiling (Cdn$/US$)	Type of contract
January 2015 – December 2016	2,000,000	3,500,000	1.04	1.18	Financial

(1) If the average monthly exchange rate is greater than 1.18, the Corporation pays $US3,500,000 multiplied by the difference between the average monthly exchange rate and 1.1270. If the monthly average exchange rate settles below 1.04 the Corporation receives $US2,000,000 multiplied by the difference between the average monthly exchange rate and 1.04.

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

	Year ended December 31, 2014	2013
Realized loss on financial oil contracts	**$ (3,884)**	$ (2,596)
Realized gain (loss) on financial natural gas contracts	**(5,107)**	8,266
Realized gain (loss) on forward foreign exchange contracts	**(136)**	605
Unrealized gain on financial oil contracts	**14,190**	5,411
Unrealized gain (loss) on physical oil contracts	**519**	(519)
Unrealized gain (loss) on financial natural gas contracts	**1,408**	(2,447)
Unrealized gain (loss) on physical natural gas contracts	**(115)**	64
Unrealized loss on forward foreign exchange contracts	**(4,056)**	(726)
Change in fair value of commodity price derivatives	**$ 2,819**	$ 8,058

Natural gas price sensitivity analysis

As at December 31, 2014, 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 $0.2 million. Fair value sensitivity is based on published forward AECO and NYMEX prices.

Oil price sensitivity analysis

As at December 31, 2014, 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 $1.6 million. Fair value sensitivity is 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 had no interest rate swap or financial contracts in place as at or during the year ended December 31, 2014 (December 31, 2013 – nil).

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.

Interest rate sensitivity analysis

For the year ended December 31, 2014, if interest rates changed by one percent with all other variables held constant, the impact on interest expense and net income would be $0.4 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's 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 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 cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities approximate their carrying amounts due to their short terms to maturity. Bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying amount.

The fair value of the financial obligation is estimated by discounting future cash payments based on the forecasted Alberta gas reference price (see note 10) multiplied by the contracted deemed volume. This fair value measurement is classified as level 3 as significant unobservable inputs, including the discount rate and forecasted Alberta gas reference prices, are used in determination of the carrying amount. The discount rate of 12.2% was determined on inception of the agreement based on the characteristics of the instrument. The forecasted Alberta gas reference prices for the remaining term are based on AECO forward market pricing with adjustments for historical differences between the Alberta reference price and market prices.

The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchy levels:

As at December 31, 2014	Gross	Netting(1)	Carrying Amount	Level 1	Fair Value Level 2	Level 3
Financial assets						
Fair value through profit and loss						
Derivatives – current	**9,595**	**(280)**	**9,315**	**–**	**9,315**	**–**
Derivatives – non-current	**149**	**(149)**	**–**	**–**	**–**	**–**
Financial liabilities						
Financial liabilities at amortized cost						
Convertible debentures	**33,810**	**–**	**33,810**	**35,052**	**–**	**–**
Senior notes	**270,690**	**–**	**270,690**	**–**	**260,000**	**–**
Fair value through profit and loss						
Derivatives – current	**2,678**	**(280)**	**2,398**	**–**	**2,398**	**–**
Derivatives – non-current	**4,021**	**(149)**	**3,872**	**–**	**3,872**	**–**
Financial obligation – current	**3,584**	**–**	**3,584**	**–**	**–**	**3,584**
Financial obligation – non-current	**11,806**	**–**	**11,806**	**–**	**–**	**11,806**

(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, 2013	Gross	Netting(1)	Carrying Amount	Level 1	Fair Value Level 2	Level 3
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.

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 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, 2014, the Corporation's ratio of net debt to operating cash flow was 4.0 to 1 (December 31, 2013 – 7.2 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 7.00% Convertible Debentures mature on December 31, 2015. While the Corporation has the option to settle all or a portion of the outstanding 7.00% Convertible Debentures through the issuance of common 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, 2014. The Corporation will apply to have the facility renewed during the next semi-annual review on or before April 30, 2015. 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 7.00% 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 7.00% Convertible 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 common shares.

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, 2014, the future minimum payments under these contractual agreements consisted of:

	Drilling Commitments	Pipeline commitments	Operating lease commitments
2015	3,533	9,560	1,712
2016	2,712	7,627	1,685
2017	1,416	5,868	1,621
2018	–	3,986	405
2019	–	3,986	–
Total	**$ 7,661**	**$ 31,027**	**$ 5,423**

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, **2014**	2013
Net income before income tax	**$ 3,366**	$ 7,620
Combined federal and provincial tax rate	**25.0%**	25.0%
Computed income tax expense	**$ 842**	$ 1,905
Increase (decrease) in income taxes resulting from:		
Non-deductible expenses	**1,493**	994
Non-taxable capital gain	**(411)**	–
Unrecognized tax asset	**(2,795)**	(2,421)
Other	**871**	(478)
Deferred income taxes	**$ –**	$ –

Income tax rates remained at 25.0 percent in 2014 and 2013 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, **2014**	2013
Property, plant and equipment	**$ 34,795**	$ 28,539
Other	**4,036**	6,287
Gas over bitumen royalty obligation	**(831)**	(737)
Decommissioning obligations	**(38,000)**	(34,089)
	$ –	$ –

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

	Year ended December 31, 2014	2013
Non-capital losses	**$ 128,702**	$ 146,703
Capital losses	**160,969**	160,969
Decommissioning obligation	**70,975**	77,551
Financial obligation	**15,390**	-
Other	**7,607**	11,055
	$ 383,643	$ 396,278

The tax losses expire between 2015 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 $507 million (December 31, 2013 – $551 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, 2014	2013
Short-term fees and other short-term benefits	**$ 3,572**	$ 3,860
Share based compensation expense	**3,675**	1,869
	$ 7,247	$ 5,729

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, 2014	2013
Production and operating	**$ 8,802**	$ 9,279
General and administrative	**26,423**	24,171
	$ 35,225	$ 33,450

During the year ended December 31, 2014, total employee compensation costs included share based compensation expense of $6.0 million (2013 – $4.0 million) with the remainder being short-term fees and other short-term benefits.

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, Acquisitions and Divestitures
Linda L. McKean
Vice President, Exploitation
Marcello M. Rapini
Vice President, Marketing

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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

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 "2015 Outlook" may constitute forward-looking statements under applicable securities laws. The forward-looking information includes, without limitation, statements regarding capital expenditure levels for 2015, the expected timing for the closing of the sale of its interest in the West Edson Property and the anticipated use, value and benefits of the TOU Shares received in exchange thereof including the expected impact on the Corporation's financial position and benefits for Perpetual's shareholders; the expected current retention of the TOU Shares and the resulting positive impact on the Corporation's borrowing base under it credit facility upon redetermination of the credit facility; the impact of the transaction on the Corporation's net asset value; the ability of the Corporation to reduce debt and manage downside risk in the current uncertain and volatile commodity price environment; prospective drilling and operational activities and capital expenditures at East and West Edson; forecast production and production type; 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, 2014 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 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 8 of this report.

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