FOURTH QUARTER 2014

Report to Shareholders for the period ended December 31, 2014

MEG Energy Corp. reported fourth quarter 2014 operational and financial results on February 5, 2015. Highlights include:

- Record quarterly production of 80,349 barrels per day (bpd) and record annual production of 71,186 bpd, more than double 2013 annual volumes;

- Record-low quarterly non-energy operating costs of $6.42 per barrel and record-low annual non-energy operating costs of $8.02 per barrel;

- Quarterly cash flow from operations of $134 million, contributing to record annual cash flow from operations of $791 million;

- Year-end cash and cash equivalents of $656 million.

"With the successful ramp-up of Christina Lake Phase 2B and the continuing implementation of MEG's RISER initiative, we have built a low-cost production base. This provides a solid foundation in the current price environment and attractive opportunities in the future," said Bill McCaffrey, President and Chief Executive Officer. "We remain focused on finding new ways to profitably grow the business by increasing production at low-capital levels, tightly managing our operating costs, and achieving the highest possible netbacks through our value chain."

MEG's annual production for 2014 averaged 71,186 bpd, an increase of 102% over 2013 volumes of 35,317 bpd, marking the company's seventh consecutive year of annual production gains. Production rates for the fourth quarter of 2014 increased to a record 80,349 bpd from comparative fourth quarter 2013 production of 42,251 bpd.

Related non-energy operating costs for the fourth quarter were a record-low $6.42 per barrel, compared to $8.09 in the fourth quarter of 2013. Annual non-energy operating costs were also at a record low of $8.02 per barrel. Lower costs on both a quarterly and annual basis are reflective of higher production volumes from Phase 2B and increased plant efficiency.

MEG had initially targeted 2014 average production volumes at 60,000 to 65,000 barrels per day at a non-energy operating cost of $8 to $10 per barrel. With strong performance in the first half of the year, production targets were upwardly revised to 65,000 to 70,000 bpd.

While fourth quarter 2014 production volumes exceeded 80,000 bpd, sales volumes were lower at approximately 70,000 bpd. The difference between production and sales was primarily due to the impact of line fill required for the start-up during the quarter of the Flanagan-Seaway pipeline, on which MEG has contracted capacity.

“With the start-up of the Flanagan-Seaway pipeline, MEG now has an additional low-cost option to move our production to the U.S. Gulf Coast,” says McCaffrey. “This is a key piece in our ‘hub and spoke’ marketing strategy that expands our ability to receive world pricing for our barrels.”

Cash flow from operations increased nearly six-fold to $134 million in the fourth quarter of 2014 from $23 million in the fourth quarter of 2013. The increase is primarily due to higher bitumen sales volumes and market price realizations, partially offset by an increase in natural gas energy costs and lower power revenues, as well as an increase in interest expense as a result of the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense.

For the full year 2014, cash flow from operations increased 213% to $791 million from $253 million in 2013, primarily reflecting the same impacts noted for the fourth quarter.

Fourth quarter 2014 operating earnings were $8 million compared to an operating loss of $33 million for the same period in 2013. The increase in operating earnings is primarily due to increased bitumen sales volumes and higher price realizations. MEG recognized operating earnings of $247 million for the full-year 2014 compared to $0.4 million in 2013.

Capital Investment

MEG’s capital investment in 2014 totaled $1.2 billion, a reduction of approximately $600 million from the company’s 2014 capital budget. Reduced capital spending reflects MEG’s focus on lower-capital cost brownfield investments and deferrals of some planned spending in light of lower commodity prices.

In December 2014, MEG announced a 2015 capital program of $305 million. Although the current program is focused primarily on sustaining and maintenance capital, MEG continues to target production growth of approximately 19% over its upwardly-revised 2014 guidance to a target of 78,000 to 82,000 barrels per day in 2015, while providing for two scheduled plant turnarounds.

OPERATIONAL AND FINANCIAL HIGHLIGHTS

The following table summarizes selected operational and financial information of the Corporation for the periods noted. All dollar amounts are stated in Canadian dollars ($ or C$) unless otherwise noted:

	Year ended December 31		2014				2013			
($ millions, except as indicated)	**2014**	**2013**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Bitumen production - bbls/d	71,186	35,317	80,349	76,471	68,984	58,643	42,251	34,246	32,144	32,531
Bitumen sales - bbls/d	67,243	33,715	70,116	69,757	70,849	58,089	35,990	32,175	32,175	32,393
Bitumen realization - $/bbl	62.67	49.28	50.48	65.12	72.75	62.28	38.22	74.33	53.98	30.04
Net operating costs - $/bbl[(1)]	12.06	10.01	10.13	10.31	14.49	13.63	11.22	9.40	8.85	10.44
Non-energy operating costs - $/bbl	8.02	9.00	6.42	7.16	9.64	9.05	8.09	9.20	10.00	8.81
Cash operating netback[(2)] - $/bbl	44.87	35.87	35.56	48.70	51.45	43.51	23.78	59.59	41.93	17.90
Cash flow from operations[(3)]	791	253	134	238	262	157	23	144	79	7
Per share, diluted[(3)]	3.52	1.13	0.60	1.06	1.16	0.70	0.10	0.64	0.35	0.03
Operating earnings (loss)[(3)]	247	0.4	8	87	111	41	(33)	56	14	(37)
Per share, diluted[(3)]	1.10	-	0.04	0.39	0.49	0.18	(0.15)	0.25	0.25	(0.16)
Revenue [(4)]	2,830	1,334	615	706	829	680	350	402	324	258
Net earnings (loss)[(5)]	(106)	(166)	(150)	(101)	249	(103)	(148)	115	(62)	(71)
Per share, basic	(0.47)	(0.75)	(0.67)	(0.45)	1.12	(0.46)	(0.67)	0.52	(0.28)	(0.32)
Per share, diluted	(0.47)	(0.75)	(0.67)	(0.45)	1.11	(0.46)	(0.67)	0.51	(0.28)	(0.32)
Total cash capital investment[(6)]	1,238	2,112	324	291	299	324	366	455	636	655
Cash, cash equivalents and short-term investments	656	1,179	656	777	840	890	1,179	647	1,204	1,803
Long-term debt[(7)]	4,366	4,005	4,366	4,218	4,016	4,162	4,005	2,858	2,923	2,823

(1) *Net operating costs include energy and non-energy operating costs, reduced by power revenue.*

(2) *Cash operating netbacks are calculated by deducting the related diluent, transportation, operating expenses and royalties from proprietary sales volumes and power revenues, on a per barrel basis.*

(3) *Cash flow from operations, Operating earnings (loss), and the related per share amounts do not have standardized meanings prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable to similar measures used by other companies. These non-GAAP measurements are reconciled to net earnings (loss) and net cash provided by (used in) operating activities in accordance with IFRS under the heading "NON-GAAP MEASUREMENTS" and discussed further in the "ADVISORY" section.*

(4) *The total of Petroleum revenue, net of royalties and Other revenue as presented on the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss).*

(5) *Includes an unrealized foreign exchange loss on translation of the U.S. dollar denominated debt of $150 million and $368 million, respectively, for the three months and year ended December 31, 2014. Includes an unrealized foreign exchange loss on translation of U.S. dollar denominated debt of $128 million and $214 million, respectively, for the three months and year ended December 31, 2013.*

(6) *Defined as total capital investment excluding capitalized interest and non-cash items.*

(7) *Includes current and long-term portions.*

The Corporation's results for the eight most recent quarters have been impacted by fluctuations in commodity prices, foreign exchange rates and production and sales volumes.

Bitumen Production

Bitumen production for the three months ended December 31, 2014 averaged 80,349 bbls/d compared to 42,251 bbls/d for the three months ended December 31, 2013. Bitumen production for the year ended December 31, 2014 averaged 71,186 bbls/d compared to 35,317 bbls/d for the year ended December 31, 2013. The increase in production volumes in the fourth quarter of 2014 compared to the fourth quarter of 2013 is primarily due to the successful ramp-up of Phase 2B and the implementation of RISER on Christina Lake Phases 1 and 2. The implementation of the RISER initiative within Phases 1 and 2 has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells into production. The Corporation achieved first production from Phase 2B in the fourth quarter of 2013. As a result of the successful ramp-up of Phase 2B, in combination with the success achieved from applying RISER to Phases 1 and 2, MEG has achieved average production in excess of 80,000 bbls/d from Christina Lake Phases 1, 2 and 2B in the fourth quarter of 2014. This level of production was initially anticipated to occur in early 2015.

Bitumen Sales

Bitumen sales for the three months ended December 31, 2014 were 70,116 bbls/d compared to production of 80,349 bbls/d for the same period. The difference between bitumen sales and production is primarily due to the transitional impact of utilizing production of approximately 7,900 bbls/d related to the fourth quarter 2014 start-up of the Flanagan South Pipeline and approximately 2,300 bbls/d in increased inventory at other locations.

Bitumen sales for the year ended December 31, 2014 were 67,243 bbls/d compared to production of 71,186 bbls/d for the same period. The difference between bitumen sales and production was primarily due to the transitional impact of utilizing production of approximately 2,000 bbls/d related to the fourth quarter 2014 start-up of the Flanagan South Pipeline and approximately 1,500 bbls/d for blend linefill for the Access Pipeline expansion in the third quarter of 2014.

Bitumen Realization

For the three months ended December 31, 2014, average bitumen realizations increased to $50.48 per barrel compared to $38.22 per barrel for the three months ended December 31, 2013, primarily due to lower differentials between the Corporation’s blend sales price and the C$/bbl West Texas Intermediate (“WTI”) price and a decrease in the cost of diluent.

The Corporation’s blend sales price differential from the C$/bbl WTI was 23.5% during the three months ended December 31, 2014 compared to a differential of 40.6% during the three months ended December 31, 2013. The C$/bbl WTI price averaged $83.08 per barrel during the three months ended December 31, 2014 compared to $102.08 per barrel during the three months ended December 31, 2013.

For the year ended December 31, 2014, average bitumen realizations increased to $62.67 per barrel compared to $49.28 per barrel the year ended December 31, 2013 primarily due to lower differentials between the Corporation’s blend sales price and C$/bbl WTI.

The C$/bbl WTI price averaged $102.74 per barrel during the year ended December 31, 2014 compared to $100.86 per barrel during the year ended December 31, 2013. The differential between the Corporation’s blend sales price and the C$/bbl WTI improved to an average of 26.0% for the year ended December 31, 2014 compared to 32.7% for the year ended December 31, 2013.

Net Operating Costs

Net operating costs are comprised of the sum of non-energy operating costs and energy operating costs, which are reduced by power revenue. Non-energy operating costs represent production operating activities excluding energy operating costs. Energy operating costs represent the cost of natural gas for the production of steam and power at the Corporation's facilities. Power revenue is the sale of surplus power not utilized by MEG to the Alberta power pool. Power is generated at the Corporation's cogeneration facilities at Christina Lake.

Net operating costs averaged $10.13 per barrel for the three months ended December 31, 2014 compared to $11.22 per barrel for the three months ended December 31, 2013. The decrease in net operating costs on a per barrel basis is primarily attributable to a decrease in the cost per barrel of non-energy operating costs, partially offset by a decrease in the average power sales price.

- Non-energy operating costs decreased to $6.42 per barrel for the three months ended December 31, 2014 compared to $8.09 per barrel for the same period in 2013. On a per barrel basis, non-energy operating costs decreased as a result of the increase in sales volumes, as relatively fixed components of operating costs are spread over a greater number of barrels, which more than offset an increase in costs.

- Power revenue decreased to $1.45 per barrel for the three months ended December 31, 2014 compared to $2.25 per barrel for the same period in 2013. The Corporation's realized power price during the three months ended December 31, 2014 averaged $31.67 per megawatt hour compared to $44.63 per megawatt hour for the same period in 2013. The decrease in the power price is mainly a result of increased power generation capacity in the province of Alberta. Power revenue had the effect of offsetting 28% of energy operating costs during the three months ended December 31, 2014 compared to 42% during the same period in 2013.

Net operating costs for the year ended December 31, 2014 averaged $12.06 per barrel compared to $10.01 per barrel for the year ended December 31, 2013. The increase in net operating costs on a per barrel basis is attributable to an increase in energy operating costs and a decrease in the average power sales price, partially offset by a decrease in non-energy operating costs on a per barrel basis.

- Energy operating costs increased to $6.30 per barrel for the year ended December 31, 2014 compared to $4.62 per barrel for the same period in 2013. Energy costs increased as a result of the increase in natural gas prices, which increased to an average of $4.62 per mcf for the year ended December 31, 2014 compared to $3.21 per mcf for the same period in 2013.

- Power revenue decreased to $2.26 per barrel for the year ended December 31, 2014 compared to $3.61 per barrel for the same period in 2013. The Corporation's realized power price during the year ended December 31, 2014 decreased to $48.83 per megawatt hour compared to $76.23 per megawatt hour in 2013. The decrease in the power price is mainly a result of increased power generation capacity in the province of Alberta in 2014 compared to 2013. During 2013, the province of Alberta was affected by significant power supply disruptions, which led to strong power prices. Power revenue had the effect of offsetting 36% of energy operating costs during the year ended December 31, 2014 compared to offsetting 78% of energy operating costs during 2013.

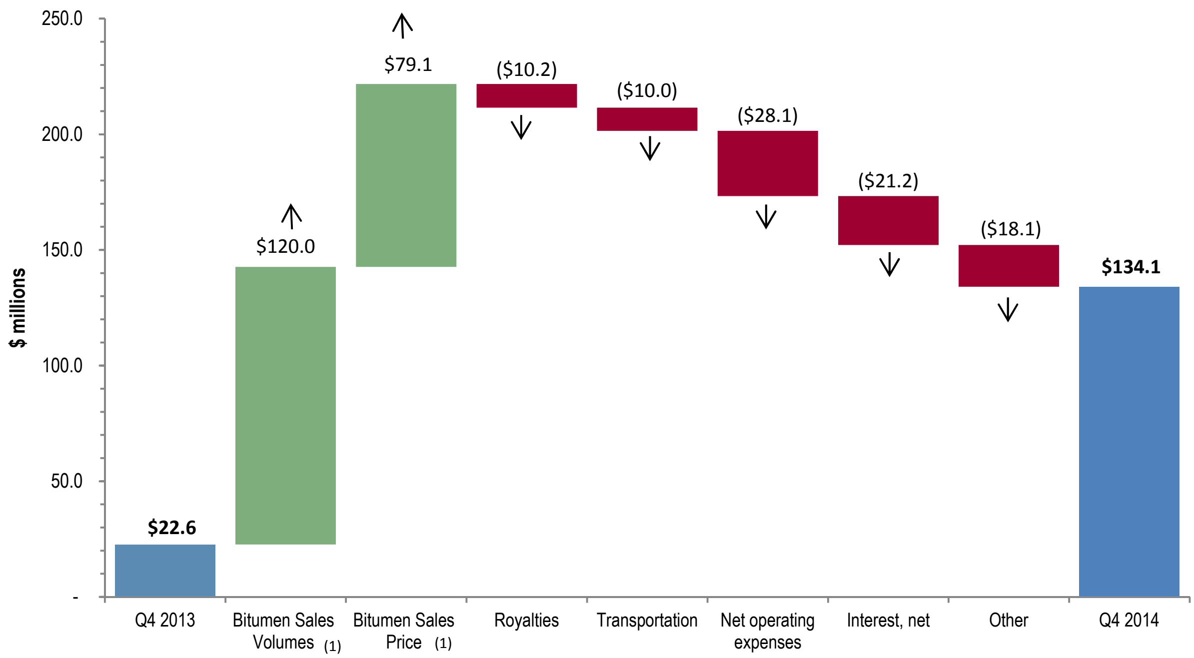
- Non-energy operating costs decreased to $8.02 per barrel for the year ended December 31, 2014 compared to $9.00 per barrel for the same period in 2013. On a per barrel basis, non-energy operating costs decreased primarily as a result of the increase in sales volumes, as relatively fixed components of operating costs are spread over a greater number of barrels. This was partially offset by an increase in planned turnaround costs which were $0.51 per barrel for an approximate three-week turnaround in 2014 compared to $0.15 per barrel for the minor turnaround in 2013.

Cash Operating Netback

Cash operating netback for the three months ended December 31, 2014 was $35.56 per barrel compared to $23.78 per barrel for the three months ended December 31, 2013. The increase in the cash operating netback in the fourth quarter of 2014 compared to the fourth quarter of 2013 is primarily due to an increase in bitumen realizations.

Cash operating netback for the year ended December 31, 2014 was $44.87 per barrel compared to $35.87 per barrel for the year ended December 31, 2013. The increase in cash operating netback for the year ended December 31, 2014 compared to the year ended December 31, 2013 is due primarily to an increase in bitumen realizations partially offset by an increase in energy operating costs.

Cash Flow from Operations



(1) *Net of diluent.*

Cash flow from operations increased to $134.1 million for the three months ended December 31, 2014 from $22.6 million for the three months ended December 31, 2013. Cash flow from operations increased primarily due to higher bitumen sales volumes and realizations, partially offset by an increase in net operating expenses and an increase in interest expense due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense.

Cash flow from operations increased to $791.5 million for the year ended December 31, 2014 from $253.4 million for the year ended December 31, 2013. Cash flow from operations increased primarily due to higher bitumen sales volumes and realizations, partially offset by an increase in net operating expenses and an increase in interest expense. Interest expense increased as a result of an increase in average debt outstanding in 2014. In addition, interest expense increased due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense.

Operating Earnings

Operating earnings for the three months ended December 31, 2014 was $8.1 million compared to an operating loss of $32.7 million for the three months ended December 31, 2013. The increase in operating earnings is primarily due to the 90% increase in bitumen sales volumes and a 32% increase in bitumen realizations, partially offset by an increase in depletion and depreciation expense, an increase in net operating expenses and the recognition of an inventory reduction of $19.7 million in the fourth quarter of 2014, due to a decrease in blend pricing.

The Corporation recognized operating earnings of $247.4 million for the year ended December 31, 2014 compared to operating earnings of $0.4 million for the year ended December 31, 2013. Operating earnings have increased in 2014 as bitumen sales volumes have doubled and bitumen realizations per barrel have increased by 27% compared to 2013. These increases were partially offset by an increase in depletion and depreciation expense, an increase in net operating expenses and the recognition of an inventory reduction of $19.7 million in the fourth quarter of 2014, due to a decrease in blend pricing.

Revenue

Revenue for the three months ended December 31, 2014 totalled $614.8 million compared to $350.3 million for the three months ended December 31, 2013. Revenue for the year ended December 31, 2014 totalled $2.8 billion compared to $1.3 billion for the year ended December 31, 2013. Revenue represents the total of Petroleum revenue, net of royalties and Other revenue.

Net Earnings (Loss)

The Corporation recognized a net loss of $150.1 million for the three months ended December 31, 2014 compared to a net loss of $148.2 million for the three months ended December 31, 2013. The net loss for the three months ended December 31, 2014 was primarily due to an unrealized foreign exchange loss of $149.9 million on the conversion of U.S. dollar denominated debt in the fourth quarter of 2014 compared to an unrealized foreign exchange loss of $127.8 million on U.S. dollar denominated debt in the fourth quarter of 2013. Also included in the net loss for the three months ended December 31, 2014 are expenses relating to a $19.7 million decrease in the value of bitumen blend inventory and $16.5 million of non-recurring field asset construction contract cancellation costs relating to a reduction of the Corporation's capital program for 2015.

The Corporation recognized a net loss of $105.5 million for the year ended December 31, 2014 compared to a net loss of $166.4 million for the year ended December 31, 2013. The net loss for the year ended December 31, 2014 included an unrealized foreign exchange loss of $368.5 million on the Corporation's U.S. dollar denominated debt. The net loss for the year ended December 31, 2013 included an unrealized foreign exchange loss of $213.7 million on U.S. dollar denominated debt. Also included in the net loss for the year ended December 31, 2014 are expenses relating to a $19.7 million decrease in the value of bitumen blend inventory and $16.5 million of non-recurring field asset construction contract cancellation costs relating to a reduction of the Corporation's capital program for 2015.

Total Cash Capital Investment

Total cash capital investment for the three months ended December 31, 2014 totalled $324.0 million compared to a total of $366.3 million for the three months ended December 31, 2013. Total cash capital investment for the year ended December 31, 2014 totalled $1.2 billion compared to a total of $2.1 billion for the year ended December 31, 2013.

Capital investment during 2014 has been focused on the initial investment in RISER 2B, engineering and procurement of long-lead items for future expansions at Christina Lake, the expansion of the Access Pipeline, and delineation drilling at Christina Lake, Surmont and the Growth Properties. In the third quarter of 2014, MEG completed the expansion of the Access Pipeline, which included the construction of a 42-inch blend line from Christina Lake to the Edmonton, Alberta area to accommodate anticipated increases in production, as well as to provide expansion capacity for future production volumes that are expected to be produced from the Christina Lake Project, the Surmont Project and from MEG's Growth Properties.

Capital Resources

The Corporation's cash and cash equivalents balance totalled $656.1 million as at December 31, 2014 compared to a cash and cash equivalents balance of $1.2 billion as at December 31, 2013. The Corporation's cash and cash equivalents balances have been impacted by an increase in cash flow from operations in 2014 and capital investments over the past year. All of the Corporation’s long-term debt is denominated in U.S. dollars. Long-term debt increased to C$4.4 billion as at December 31, 2014 from C$4.0 billion as at December 31, 2013 due to the decrease in the value of the Canadian dollar relative to the U.S. dollar. All of MEG’s long-term debt is “covenant lite” in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation’s crude oil reserves. The first maturity of any of the Corporation’s long-term debt obligations is March 2020.

As at December 31, 2014, the Corporation's capital resources included $656.1 million of cash and cash equivalents, an additional undrawn US$2.5 billion syndicated revolving credit facility and a US$500 million guaranteed letter of credit facility. During the fourth quarter of 2014, the Corporation increased the syndicated revolving credit facility from US$2.0 billion to US$2.5 billion and extended the maturity of the revolving credit facility to November 2019. During the fourth quarter of 2014, the Corporation obtained a five-year US$500 million guaranteed letter of credit facility guaranteed by Export Development Canada (“EDC”). The facility matures November 2019. Letters of credit issued under the facility with EDC will not consume capacity of the revolving credit facility. Similar to the Corporation’s long-term debt, the revolving credit facility is “covenant lite” in structure.

BUSINESS ENVIRONMENT

The following table shows industry commodity pricing information and foreign exchange rates on a quarterly and year-to-date basis to assist in understanding the impact of commodity prices and foreign exchange rates on the Corporation's financial results:

	Year ended December 31		2014				2013			
	2014	2013	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Commodity Prices										
Crude oil prices										
West Texas Intermediate (WTI) US$/bbl at Cushing	93.00	97.96	73.15	97.16	102.99	98.68	97.43	105.83	94.22	94.37
West Texas Intermediate (WTI) C$/bbl at Cushing	102.74	100.86	83.08	105.84	112.31	108.89	102.08	109.90	96.42	95.21
Western Canadian Select (WCS) C$/bbl at Hardisty	81.10	74.97	66.74	83.82	90.44	83.41	68.31	91.75	76.82	63.01
Differential – WTI vs WCS (C$/bbl)	21.63	25.89	16.34	22.02	21.87	25.48	33.77	18.15	19.60	32.20
Differential – WTI vs WCS (%)	21.1%	25.7%	19.7%	20.8%	19.5%	23.4%	33.1%	16.5%	20.3%	33.8%
Diluent (C5+ at Edmonton) C$/bbl	102.92	104.72	81.98	101.72	114.72	113.26	99.19	107.81	103.68	108.21
Natural gas prices										
AECO (C$/mcf)	4.50	3.16	3.58	4.00	4.70	5.69	3.52	2.42	3.51	3.18
Electric power prices										
Alberta power pool (C$/MWh)	49.37	80.22	30.55	63.91	42.43	60.58	48.60	83.61	123.41	65.26
Foreign exchange rates										
C$ equivalent of 1 US$ - average	1.1047	1.0296	1.1357	1.0893	1.0905	1.1035	1.0477	1.0385	1.0233	1.0089
C$ equivalent of 1 US$ - period end	1.1601	1.0636	1.1601	1.1208	1.0676	1.1053	1.0636	1.0285	1.0512	1.0156

Crude Oil Pricing

The price of WTI is the current benchmark for mid-continent North American crude oil prices, at Cushing Oklahoma, and its Canadian dollar equivalent is the basis for determining royalties on the Corporation's bitumen sales. The WTI price averaged US$73.15 per barrel in the fourth quarter of 2014 compared to US$97.16 per barrel for the third quarter of 2014. The WTI price decreased to US$73.15 per barrel in the three months ended December 31, 2014 from US$97.43 per barrel for the three months ended December 31, 2013. The decrease is primarily due to an increase in global light crude oil supply. The WTI price averaged US$93.00 per barrel for the year ended December 31, 2014 compared to US$97.96 per barrel for the year ended December 31, 2013. WTI decreased on a year-to-date basis in 2014 compared to 2013, primarily as a result of increased global supply in the fourth quarter of 2014 which resulted in an approximate 30 percent decrease in average pricing from the second quarter of 2014.

The Western Canadian Select ("WCS") benchmark reflects North American prices at Hardisty, Alberta. WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. WCS typically trades at a differential below the WTI benchmark price. In the fourth quarter of 2014, WCS Canadian dollar pricing benefited from the weakening of the Canadian dollar relative to the U.S. dollar, increased refinery demand in the U.S. Midwest and the commencement of operations of the Flanagan South Pipeline between Chicago and Cushing. In addition, WCS Canadian dollar pricing also benefited from continued structural improvements for market access to the U.S. Gulf Coast and to other new markets not previously accessible. The WTI to WCS differential averaged 19.7% for the fourth quarter of 2014, compared to 33.1% for the fourth quarter of 2013. The WTI to WCS differential averaged 21.1% for the year ended December 31, 2014 compared to a WTI to WCS differential of 25.7% for the year ended December 31, 2013.

Pipeline congestion and consequent apportionment of capacity between western Canada and the U.S. coastal markets can negatively impact the price MEG receives for its blend sales. Recent additions of crude-by-rail, new pipeline connections from the U.S. mid-continent to the U.S. Gulf Coast, and refinery modifications in the U.S. Midwest, are collectively relieving some of this price pressure. Once complete, these factors should help realign Canadian crude oil prices with international benchmarks.

Proprietary petroleum sales represents MEG's revenue from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). AWB is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent. Bitumen realization as discussed in this document represents the Corporation's realized proprietary blend sales revenues, net of the cost of diluent. The cost of blending is impacted by the amount of diluent required and the Corporation's cost of purchasing diluent. A portion of the cost of diluent is effectively recovered in the sales price of the blended product. The cost of diluent is impacted by WTI pricing. The average Edmonton benchmark diluent price decreased to $81.98 per barrel for the three months ended December 31, 2014 compared to $99.19 per barrel for the three months ended December 31, 2013. The benchmark diluent price decreased to an average of $102.92 per barrel for the year ended December 31, 2014 compared to $104.72 per barrel for the year ended December 31, 2013.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, as it is used to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $3.58 per mcf for the three months ended December 31, 2014 compared to $3.52 per mcf for the three months ended December 31, 2013. The AECO natural gas price averaged $4.50 per mcf for the year ended December 31, 2014 compared to $3.16 per mcf for year ended December 31, 2013. Despite a year-over-year increase in average natural gas prices, there is continued weakness in the natural gas price with strong production in Alberta, an increase of gas in storage and reduced demand as a result of mild winter conditions across North America.

Power Prices

Electric power prices impact the price that the Corporation receives on the sale of surplus power from the Corporation's cogeneration facilities. The Alberta power pool price averaged $30.55 per megawatt hour during the three months ended December 31, 2014 compared to $48.60 per megawatt hour for the three months ended December 31, 2013. The Alberta power pool price averaged $49.37 per megawatt hour for the year ended December 31, 2014 compared to $80.22 per megawatt hour for the year ended December 31, 2013. The decrease in the Alberta power pool price is mainly a result of increased year-over-year power generation capacity in the province. Incremental power generation in the province is anticipated to continue to moderate power prices.

Foreign Exchange Rates

Changes in the value of the Canadian dollar relative to the U.S. dollar have an impact on the Corporation's blend sales, as blend sales prices are determined by reference to U.S. benchmarks. Changes in the value of the Canadian dollar relative to the U.S. dollar also have an impact on principal and interest payments on the Corporation's U.S. dollar denominated debt. A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on blend sales and a negative impact on principal and interest payments, while an increase in the value of the Canadian dollar has a negative impact on blend sales and a positive impact on principal and interest payments. The Corporation recognizes unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt at each reporting date. As at December 31, 2014, the Canadian dollar, at a rate of 1.1601, had decreased in value by approximately 4% against the U.S. dollar compared to its value as at September 30, 2014, when the rate was 1.1208. The value of the Canadian dollar as at December 31, 2014 has decreased by approximately 9% from its value as at December 31, 2013, when the rate was 1.0636.

RESULTS OF OPERATIONS
COMPARISON OF THE THREE MONTHS ENDED DECEMBER 31, 2014 TO DECEMBER 31, 2013

	Three months ended December 31	
	2014	**2013**
Bitumen production – bbls/d	80,349	42,251
Bitumen sales – bbls/d	70,116	35,990
Steam to oil ratio (SOR)	2.5	2.9

Bitumen Production

Production for the three months ended December 31, 2014 averaged 80,349 bbls/d compared to 42,251 bbls/d for the three months ended December 31, 2013. The increase in production volumes in 2014 compared to 2013 is due to the successful ramp-up of Phase 2B and the implementation of RISER on Christina Lake Phases 1 and 2. The implementation of the RISER initiative within Phases 1 and 2 has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells on production. The Corporation achieved first production from Phase 2B in the fourth quarter of 2013. As a result of the successful ramp-up of Phase 2B, along with the success achieved from applying RISER to Phases 1 and 2, MEG has achieved average production in excess of 80,000 bbls/d from Christina Lake Phases 1, 2 and 2B in the fourth quarter of 2014. This level of production was initially anticipated to occur in early 2015.

Bitumen Sales

Bitumen sales for the three months ended December 31, 2014 were 70,116 bbls/d compared to production of 80,349 bbls/d for the same period. The difference between bitumen sales and production is primarily due to the transitional impact of utilizing production of approximately 7,900 bbls/d related to the fourth quarter 2014 start-up of the Flanagan South Pipeline and approximately 2,300 bbls/d in increased inventory at other locations.

Steam to Oil Ratio

The Corporation continues to focus on increasing production and improving efficiency of current production through a lower SOR, which is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced.

The Corporation's average SOR was 2.5 for the three months ended December 31, 2014 and 2.9 for the three months ended December 31, 2013. As expected, the average SOR in 2014 has decreased from an SOR of 2.9 for the fourth quarter of 2013, as more Phase 2B well pairs have now been converted to production mode, and also as a result of the continued implementation of RISER at Phases 1 and 2.

Operating Cash Flow

Operating cash flow is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of the Corporation's efficiency and its ability to fund future capital investments.

	Three months ended December 31	
($000)	**2014**	**2013**
Petroleum sales – proprietary[(1)]	$ 592,518	$ 293,657
Diluent	(266,869)	(167,094)
	325,649	126,563
Royalties	(19,180)	(8,979)
Transportation expense	(19,028)	(5,734)
Operating expenses	(74,653)	(44,602)
Power revenue	9,339	7,448
Transportation revenue	7,313	4,058
Operating cash flow[(2)]	**$ 229,440**	**$ 78,754**

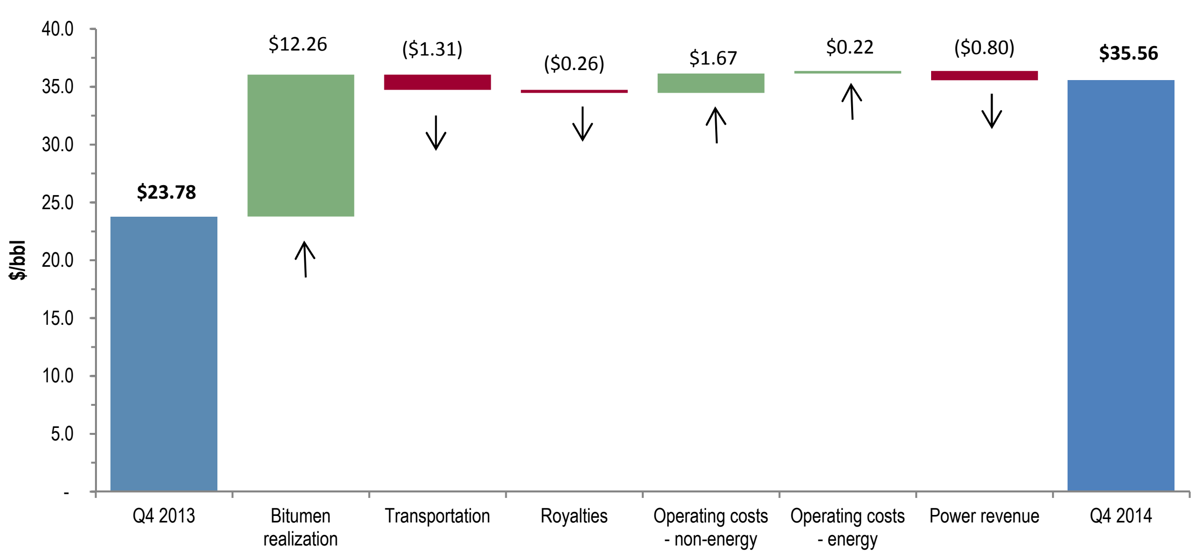
(1) *Proprietary petroleum sales represents MEG's revenue from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.*

(2) *A Non-GAAP measure as defined in the "NON-GAAP MEASUREMENTS" section of this document.*

Operating cash flow increased due to an increase in blend sales, partially offset by increases in diluent, operating expenses, transportation expenses and royalties. The increase in blend sales in the three months ended December 31, 2014 compared to the three months ended December 31, 2013 is due to a 92% increase in sales volumes and a 5% increase in the average realized blend price. Sales volumes have increased as a result of the increase in production volumes due to the start-up of Phase 2B in the fourth quarter of 2013 and the implementation of RISER on Christina Lake Phases 1 and 2.

The total cost of diluent increased to $266.9 million for the three months ended December 31, 2014 from $167.1 million for the three months ended December 31, 2013 primarily due to the increase in bitumen sales and the corresponding higher volumes of diluent required for the increased blend sales volumes.

Cash Operating Netback



The following table summarizes the Corporation's cash operating netback for the three months ended December 31:

($/bbl)	Three months ended December 31	
	2014	**2013**
Bitumen realization[1]	$ 50.48	$ 38.22
Transportation[2]	(1.82)	(0.51)
Royalties	(2.97)	(2.71)
	45.69	**35.00**
Operating costs – non-energy	(6.42)	(8.09)
Operating costs – energy	(5.16)	(5.38)
Power revenue	1.45	2.25
Net operating costs	**(10.13)**	**(11.22)**
Cash operating netback	**$ 35.56**	**$ 23.78**

(1) *Blend sales net of diluent costs.*

(2) *Transportation revenue less transportation expenses. Transportation costs include rail, Stonefell Terminal costs and third-party pipelines, as well as MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements.*

Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary blend sales revenues, net of the cost of diluent. Bitumen realization averaged $50.48 per barrel during the three months ended December 31, 2014 compared to $38.22 per barrel for the three months ended December 31, 2013. The increase is primarily attributable to lower differentials between the Corporation's blend sales price and WTI. The improvement of differentials is due to continued structural improvements for market access to the U.S. Gulf Coast and to other new markets not previously accessible, partially offset by a decrease in the average WTI price quarter over quarter. For the three months ended December 31, 2014, the Corporation's cost of diluent was $93.00 per barrel compared to $108.89 per barrel for the three months ended December 31, 2013.

Transportation

Transportation costs include rail, third-party pipelines and the Stonefell Terminal costs, as well as MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements. On a per barrel basis, transportation costs averaged $1.82 per barrel for the three months ended December 31, 2014 compared to $0.51 per barrel for the three months ended December 31, 2013. The increase in transportation costs is primarily due to the use of rail shipments in 2014, costs associated with the Corporation's Stonefell Terminal, which commenced operations in late 2013, and the use of third-party pipelines.

Royalties

The Corporation's royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. The applicable royalty rates change depending on whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated enough net revenues to recover its cumulative costs. The royalty rate applicable to pre-payout oil sands operations starts at 1% of bitumen sales and increases for every dollar that the WTI crude oil price in Canadian dollars is priced above $55 per barrel, to a maximum of 9% when the WTI crude oil price is $120 per barrel or higher. All of the Corporation's projects are currently pre-payout.

Royalties averaged $2.97 per barrel during the fourth quarter of 2014 compared to $2.71 per barrel for the fourth quarter of 2013. The Corporation's royalty rate, expressed as a percentage of bitumen realizations, averaged 5.9% for the three months ended December 31, 2014 compared to 7.1% for the three months ended December 31, 2013. The decrease in royalty rate in the fourth quarter of 2014 is primarily due to the decrease in WTI from C$102.08 per barrel in the fourth quarter of 2013 to C$83.08 per barrel in the fourth quarter of 2014. The increase in royalties on a per barrel basis for the three months ended December 31, 2014 compared to the same period in 2013 is primarily attributable to the increase in bitumen realizations.

Net Operating Costs

Non-energy operating costs

Non-energy operating costs averaged $6.42 per barrel for the three months ended December 31, 2014 compared to $8.09 per barrel for the three months ended December 31, 2013. The decrease is primarily due to the increase in Phase 2B sales volumes, as relatively fixed components of operating costs are spread over a greater number of barrels, which more than offset an increase in costs.

Energy related operating costs

Energy related operating costs averaged $5.16 per barrel for the three months ended December 31, 2014 compared to $5.38 per barrel for the same period in 2013. The decrease in energy operating costs for the fourth quarter of 2014 compared to the fourth quarter of 2013 is primarily attributable to a lower SOR, resulting in lower energy requirements and lower natural gas prices. The Corporation's natural gas purchase price averaged $3.50 per mcf during the fourth quarter of 2014 and $3.55 per mcf during the fourth quarter of 2013.

Power revenue

The Corporation operates two 85 megawatt cogeneration facilities which produce steam for its SAGD operations. MEG's Christina Lake facilities utilize waste heat recovered from its cogeneration facilities and a portion of the power generated. Surplus power is sold into the Alberta power pool.

Power revenue averaged $1.45 per barrel for the three months ended December 31, 2014 compared to $2.25 per barrel for the three months ended December 31, 2013. The decrease in power revenue per barrel is primarily due to a lower average Alberta power pool price. During the three months ended December 31, 2014, the Corporation's average realized power price was $31.67 per megawatt hour compared to $44.63 per megawatt hour for the same period in 2013.

RESULTS OF OPERATIONS
COMPARISON OF YEAR ENDED DECEMBER 31, 2014 TO DECEMBER 31, 2013

	Year ended December 31	
	2014	**2013**
Bitumen production – bbls/d	71,186	35,317
Bitumen sales – bbls/d	67,243	33,715
Steam to oil ratio (SOR)	2.5	2.6

Bitumen Production

Production for 2014 averaged 71,186 bbls/d compared to 35,317 bbls/d for 2013. The increase in production volumes in 2014 compared to 2013 is due to the successful ramp-up of Phase 2B and the implementation of RISER on Christina Lake Phases 1 and 2. The implementation of the RISER initiative within Phases 1 and 2 has improved reservoir efficiency and allowed for redeployment of steam, thereby enabling the Corporation to place additional wells on production. The Corporation achieved first production from Phase 2B in the fourth quarter of 2013. As a result of the successful ramp-up of Phase 2B, along with the success achieved from applying RISER to Phases 1 and 2, MEG has achieved average production in excess of 80,000 bbls/d from Christina Lake Phases 1, 2 and 2B in the fourth quarter of 2014. This level of production was initially anticipated to occur in early 2015.

Bitumen Sales

Bitumen sales for the year ended December 31, 2014 were 67,243 bbls/d compared to production of 71,186 bbls/d for the same period in 2014. The difference between bitumen sales and production was primarily due to the transitional impact of utilizing production of approximately 2,000 bbls/d related to the fourth quarter 2014 start-up of the Flanagan South Pipeline and approximately 1,500 bbls/d for blend linefill for the Access Pipeline expansion in the third quarter of 2014.

Steam to Oil Ratio

The Corporation continues to focus on increasing production and improving efficiency of current production through a lower SOR, which is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced.

The SOR averaged 2.5 during the year ended December 31, 2014 and 2.6 for the year ended December 31, 2013. As expected, the average SOR in 2014 has decreased from an SOR of 2.9 for the fourth quarter of 2013, as more Phase 2B well pairs have now been converted to production mode, and also as a result of the continued implementation of RISER at Phases 1 and 2.

Operating Cash Flow

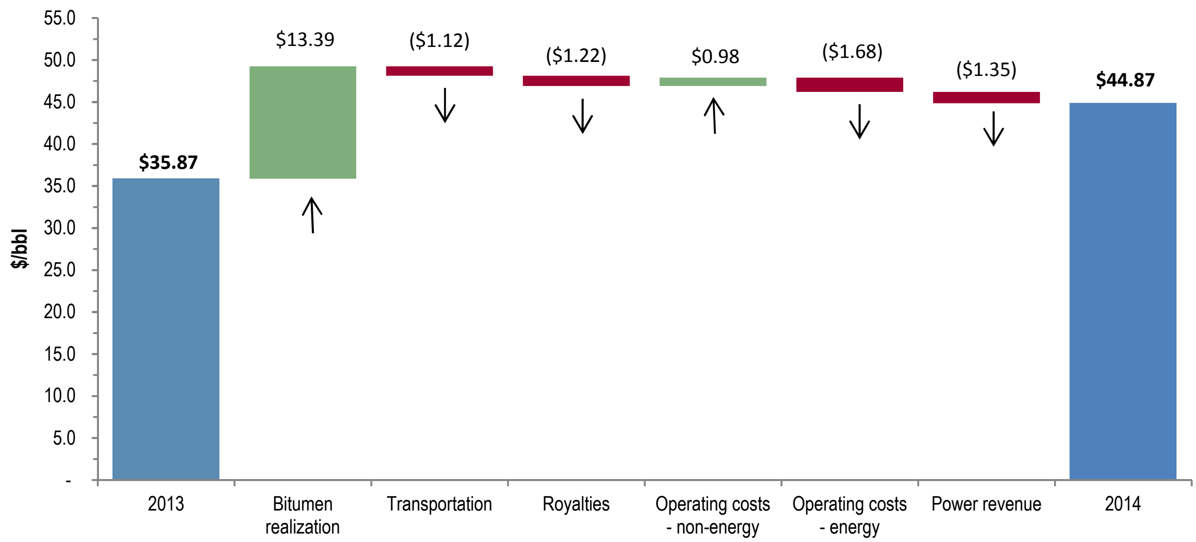
	Year ended December 31	
($000)	**2014**	**2013**
Petroleum sales – proprietary[1]	$ 2,701,801	$ 1,207,650
Diluent	(1,163,637)	(601,191)
	1,538,164	606,459
Royalties	(107,074)	(38,643)
Transportation expense	(64,442)	(22,457)
Operating expenses	(351,534)	(167,586)
Power revenue	55,352	44,456
Transportation revenue	30,625	19,284
Operating cash flow[2]	**$ 1,101,091**	**$ 441,513**

(1) Proprietary petroleum sales represents MEG's revenue from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.

(2) A Non-GAAP measure as defined in the "NON-GAAP MEASUREMENTS" section of this document.

Operating cash flow increased due to an increase in blend sales partially offset by increases in diluent, operating expenses and royalties. Blend sales for the year ended December 31, 2014 were $2.7 billion compared to $1.2 billion for the year ended December 31, 2013. The increase in blend sales in 2014 compared to 2013 is due to a 100% increase in sales volumes combined with a 12% increase in the average realized blend price. The cost of diluent for the year ended December 31, 2014 was $1.2 billion compared to $0.6 billion for the year ended December 31, 2013. The total cost of diluent increased primarily due to the increase in bitumen sales and the corresponding higher volumes of diluent required for the increased blend sales volumes.

Cash Operating Netback



The following table summarizes the Corporation's cash operating netback for the year ended December 31:

($/bbl)	**Year ended December 31**	
	2014	**2013**
Bitumen realization[(1)]	$ 62.67	$ 49.28
Transportation[(2)]	(1.38)	(0.26)
Royalties	(4.36)	(3.14)
	56.93	**45.88**
Operating costs – non-energy	(8.02)	(9.00)
Operating costs – energy	(6.30)	(4.62)
Power revenue	2.26	3.61
Net operating costs	**(12.06)**	**(10.01)**
Cash operating netback	**$ 44.87**	**$ 35.87**

(1) Blend sales net of diluent costs.

(2) Defined as transportation revenue less transportation expenses. Transportation costs include rail, Stonefell Terminal costs, third-party pipelines as well as MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements.

Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary blend sales revenues, net of the cost of diluent. Bitumen realization averaged $62.67 per barrel for the year ended December 31, 2014 compared to $49.28 per barrel for the year ended December 31, 2013. The increase is primarily due to lower differentials between the Corporation's blend sales price and WTI. The improvement of differentials is due to continued structural improvements for market access to the U.S. Gulf Coast and to other new markets not previously accessible.

For the year ended December 31, 2014, the cost of diluent was $105.94 per barrel compared to $109.60 per barrel for the year ended December 31, 2013.

Transportation

Transportation costs include rail, Stonefell Terminal costs and third-party pipelines as well as MEG's share of the operating costs for the Access Pipeline, net of third-party recoveries on diluent transportation arrangements. Transportation costs averaged $1.38 per barrel for 2014 compared to $0.26 per barrel for 2013. The increase in transportation costs is primarily due to the use of rail shipments in 2014, and to a lesser extent, costs associated with the Corporation's Stonefell Terminal, which commenced operations in late 2013.

Royalties

Royalties averaged $4.36 per barrel during 2014 compared to $3.14 per barrel for 2013. The Corporation's royalty rate, expressed as a percentage of bitumen realizations, averaged 7.0% for the year ended December 31, 2014 compared to 6.4% for 2013. The increase in royalties for the year ended December 31, 2014 compared to the same period in 2013 is attributable to the increase in bitumen realizations, the increase in sales volumes and the increase in the Canadian dollar price of WTI.

Net Operating Costs

Non-energy operating costs

Non-energy operating costs averaged $8.02 per barrel for the year ended December 31, 2014 compared to $9.00 per barrel for the year ended December 31, 2013. Non-energy operating costs include $0.51 per barrel for the approximately three-week planned turnaround in the second quarter of 2014 compared to $0.15 per barrel for the minor turnaround carried out in the second quarter of 2013. The increase in non-energy operating costs was offset on a per barrel basis by higher sales volumes as relatively fixed components of operating costs are spread over a greater number of barrels, which more than offset an increase in costs.

Energy related operating costs

Energy related operating costs averaged $6.30 per barrel for the year ended December 31, 2014 compared to $4.62 per barrel for the year ended December 31, 2013. The increase in energy operating costs on a per barrel basis is attributable to the increase in natural gas prices. The Corporation's natural gas purchase price averaged $4.62 per mcf during 2014 compared to $3.21 per mcf for 2013.

Power revenue

Power revenue averaged $2.26 per barrel for the year ended December 31, 2014 compared to $3.61 per barrel for the year ended December 31, 2013. The Corporation's average realized power price during the year ended December 31, 2014 was $48.83 per megawatt hour compared to $76.23 per megawatt hour for the same period in 2013. The decrease in the power price is mainly a result of increased power generation capacity in the province of Alberta. During 2013, the province of Alberta was affected by significant power supply disruptions, which led to strong power prices.

OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Petroleum revenue – third party	$ 24,800	$ 54,154	$ 149,260	$ 101,750
Purchased product and storage	(30,862)	(55,285)	(163,387)	(104,115)
Net marketing activity(1)	$ (6,062)	$ (1,131)	$ (14,127)	$ (2,365)

(1) Net marketing activity is a non-GAAP measure as defined in the "NON-GAAP MEASUREMENTS" section.

Net marketing activity includes the Corporation's increased activities toward enhancing its ability to transport proprietary crude oil products to a wider range of markets in the United States. Accordingly, the Corporation has entered into product storage arrangements and transportation arrangements for rail, barge and U.S.-based pipelines. These arrangements are kept in place to optimize the value of all barrels sold to the marketplace. To the extent that the Corporation is not utilizing these arrangements for proprietary purposes, MEG purchases and sells third-party crude oil and related products to optimize the returns on these transportation and storage arrangements.

Depletion and Depreciation

	Three months ended December 31		Year ended December 31	
($000)	2014	2013	2014	2013
Depletion and depreciation	$ 100,722	$ 51,508	$ 378,544	$ 189,147
Depletion and depreciation rate per barrel	$ 15.61	$ 15.56	$ 15.42	$ 15.37

Depletion and depreciation expense was $100.7 million for the three months ended December 31, 2014 compared to $51.5 million for the same period in 2013. Depletion and depreciation expense for the year ended December 31, 2014 totalled $378.5 million compared to $189.1 million for the same period in 2013. The increases are primarily due to the 95% increase in bitumen sales volumes for the fourth quarter of 2014, and a 99% increase in bitumen sales volumes for the year ended December 31, 2014, compared to the same periods in 2013. The depletion and depreciation rate for the three months ended December 31, 2014 was $15.61 per barrel compared to $15.56 per barrel for the three months ended December 31, 2013. Depletion and depreciation expense was $15.42 per barrel for the year ended December 31, 2014 compared to $15.37 per barrel for the year ended December 31, 2013.

The Corporation's producing oil sands properties are depleted on a unit-of-production basis based on estimated proved reserves. Major facilities and equipment are depreciated on a unit-of-production basis over the estimated total productive capacity of the facilities and equipment. Pipeline and storage assets are depreciated on a straight-line basis over their estimated useful lives.

General and Administrative

	Three months ended December 31		Year ended December 31	
($000)	2014	2013	2014	2013
General and administrative costs	$ 42,753	$ 34,702	$ 145,949	$ 123,194
Capitalized general and administrative costs	(8,232)	(12,040)	(34,583)	(30,366)
General and administrative expense	$ 34,521	$ 22,662	$ 111,366	$ 92,828
General and administrative expense per barrel of production	$ 4.67	$ 5.83	$ 4.29	$ 7.20

General and administrative expense for the three months ended December 31, 2014 was $34.5 million compared to $22.7 million for the three months ended December 31, 2013. General and administrative expense for the year ended December 31, 2014 was $111.4 million compared to $92.8 million for the year ended December 31, 2013.

The increase in general and administrative expense was offset on a per barrel basis by higher production volumes, as expenses are spread over a greater number of barrels, which more than offset an increase in costs.

Stock-based Compensation

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Stock-based compensation costs	$ 16,471	$ 14,192	$ 62,484	$ 50,059
Capitalized stock-based compensation costs	(3,725)	(4,532)	(14,174)	(11,267)
Stock-based compensation expense	$ 12,746	$ 9,660	$ 48,310	$ 38,792

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs") and performance share units ("PSUs") to directors, officers, employees and consultants is recognized by the Corporation as stock-based compensation expense. Fair value is determined using the Black-Scholes option pricing model. Stock-based compensation expense was $12.7 million for the three months ended December 31, 2014 compared to $9.7 million for the three months ended December 31, 2013. Stock-based compensation expense for the year ended December 31, 2014 was $48.3 million compared to $38.8 million for the year ended December 31, 2013. The increase in stock-based compensation expense is due to the growth in the Corporation's staff.

The Corporation capitalizes a portion of stock-based compensation associated with capitalized salaries and benefits. The Corporation capitalized $3.7 million of stock-based compensation for the three months ended December 31, 2014 compared to $4.5 million during the three months ended December 31, 2013. The Corporation capitalized $14.2 million of stock-based compensation for the year ended December 31, 2014 compared to $11.3 million for the year ended December 31, 2013.

Research and Development

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Research and development	$ 2,197	$ 1,645	$ 6,003	$ 5,588

Research and development expenditures related to the Corporation's research of crude quality improvement and related technologies have been expensed. Research and development expenditures were $2.2 million for the three months ended December 31, 2014 compared to $1.6 million for the three months ended December 31, 2013. Research and development expenditures were $6.0 million for the year ended December 31, 2014 compared to $5.6 million for the year ended December 31, 2013.

Net Foreign Exchange Gain (Loss)

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Unrealized foreign exchange gain (loss) on:				
Long-term debt	$ (149,919)	$ (127,834)	$ (368,450)	$ (213,715)
US$ denominated cash and cash equivalents	10,910	15,409	35,301	36,353
Unrealized loss on foreign exchange	(139,009)	(112,425)	(333,149)	(177,362)
Realized loss on foreign exchange	(1,781)	(1,180)	(5,480)	(2,916)
Net foreign exchange loss	$ (140,790)	$ (113,605)	$ (338,629)	$ (180,278)
US$/C$ exchange rates:				
Beginning of period	1.1208	1.0285	1.0636	0.9949
End of period	1.1601	1.0636	1.1601	1.0636

The Corporation recognized a net foreign exchange loss of $140.8 million for the three months ended December 31, 2014 compared to a net foreign exchange loss of $113.6 million for the three months ended December 31, 2013. The net foreign exchange loss for the fourth quarter of 2014 is primarily due to an unrealized foreign exchange loss on the translation of U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar by approximately 4% during the quarter. In the fourth quarter of 2013, the Canadian dollar weakened in value by approximately 3%.

The Corporation recognized a net foreign exchange loss of $338.6 million for the year ended December 31, 2014 compared to a net foreign exchange loss of $180.3 million for the year ended December 31, 2013. The increase in the net foreign exchange loss is primarily due to an unrealized foreign exchange loss on the translation of U.S. dollar denominated debt as a result of weakening of the Canadian dollar compared to the U.S. dollar by approximately 9% during the year ended December 31, 2014. During the year ended December 31, 2013, the Canadian dollar weakened in value by approximately 7%.

Net Finance Expense

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Total interest expense	$ 69,000	$ 60,679	$ 265,140	$ 186,835
Less capitalized interest	(14,901)	(22,911)	(75,975)	(76,529)
Net interest expense	54,099	37,768	189,165	110,306
Accretion on decommissioning provision	1,270	1,017	4,535	4,763
Unrealized fair value loss (gain) on embedded derivative financial liabilities	2,673	(2,097)	(2,652)	(14,352)
Unrealized fair value loss (gain) on interest rate swaps	2,771	159	1,183	(4,904)
Realized loss on interest rate swaps	1,311	1,212	5,056	4,720
Unrealized fair value loss (gain) on other assets	-	919	(429)	-
Net finance expense	$ 62,124	$ 38,978	$ 196,858	$ 100,533
Average effective interest rate[1]	5.8%	5.8%	5.8%	5.6%

(1) *Defined as the weighted average interest rate of the senior secured term loan and senior unsecured notes outstanding, including the impact of interest rate swaps.*

Total interest expense, before capitalization, was $69.0 million for the three months ended December 31, 2014 compared to $60.7 million for the three months ended December 31, 2013. Total interest expense increased for the three months ended December 31, 2014 primarily as a result of an increase in interest expense as a result of the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense. Total interest expense for the year ended December 31, 2014 was $265.1 million compared to $186.8 million for the year ended December 31, 2013. Total interest expense for the year ended December 31, 2014 increased primarily as a result of an increase in average debt outstanding in 2014. In addition, interest expense increased due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense.

In the first quarter of 2013, the senior secured term loan was increased by US$300.0 million to approximately US$1.3 billion. In the fourth quarter of 2013, the Corporation issued US$1.0 billion in aggregate principal amount of 7.0% senior unsecured notes. In the fourth quarter of 2014, the Corporation extended and increased its revolving credit facility from US$2.0 billion to US$2.5 billion. The revolving credit facility was undrawn throughout 2013 and 2014 and remains undrawn at December 31, 2014.

The Corporation recognized an unrealized loss on embedded derivative financial liabilities of $2.7 million for the three months ended December 31, 2014 compared to an unrealized gain of $2.1 million for the three months ended December 31, 2013. The Corporation recognized an unrealized gain on embedded derivative financial liabilities of $2.7 million for the year ended December 31, 2014 compared to an unrealized gain of $14.4 million for the year ended December 31, 2013. These gains and losses relate to the change in fair value of the interest rate floor associated with the Corporation's senior secured credit facilities. The interest rate floor is considered an embedded derivative as the floor rate was higher than the London Interbank Offered Rate ("LIBOR") at the time that the debt agreements were entered into. Accordingly, the fair value of the embedded derivatives at the time the debt agreements were entered into was netted against the carrying value of the long-term debt and is amortized over the life of the debt agreements. The fair value of the embedded derivative is included in derivative financial liabilities on the balance sheet and gains and losses associated with changes in the fair value of the embedded derivative are included in net finance expense.

The Corporation has entered into interest rate swap contracts to effectively fix the interest rate at approximately 4.4% on US$748.0 million of the US$1.3 billion senior secured term loan until September 30, 2016. The Corporation realized a loss of $1.3 million for the three months ended December 31, 2014 and a loss of $5.1 million for the year ended December 31, 2014, on the interest rate swap contracts. This compared to a loss of $1.2 million for the three months ended December 31, 2013 and a loss of $4.7 million for the year ended December 31, 2013. In addition, the Corporation recognized an unrealized loss on the interest rate swaps contracts of $2.8 million for the three months ended December 31, 2014 and an unrealized loss of $1.2 million for the year ended December 31, 2014. This compared to an unrealized loss of $0.2 million for the three months ended December 31, 2013 and an unrealized gain of $4.9 million for year ended December 31, 2013.

Other Expenses

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Inventory write-down	$ 19,668	$ -	$ 19,668	$ -
Contract cancellation costs	16,455	-	16,455	-
Other expenses	$ 36,123	$ -	$ 36,123	$ -

The Corporation recognized other expenses of $36.1 million for the three months and year ended December 31, 2014 (three months and year ended December 31, 2013 - $nil). Other expenses include $19.7 million relating to the decrease in value of bitumen blend inventory as a result of the recent decline in global crude oil prices and $16.5 million of non-recurring field asset construction contract cancellation costs as a result of the reduction of the Corporation's capital program for 2015.

Income Taxes

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Deferred income tax expense (recovery)	$ (14,007)	$ (2,857)	$ 85,776	$ 22,347

The Corporation recognized a deferred income tax recovery of $14.0 million for the three months ended December 31, 2014 compared to a deferred income tax recovery of $2.9 million for the three months ended December 31, 2013. The Corporation recognized a deferred income tax expense of $85.8 million for the year ended December 31, 2014 compared to a deferred income tax expense of $22.3 million for the year ended December 31, 2013.

The Corporation's effective tax rate on earnings is impacted by permanent differences and variances in taxable capital losses not recognized. The significant differences are:

- The permanent difference due to the non-taxable portion of unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the three months ended December 31, 2014, the non-taxable loss was $75.0 million compared to a non-taxable loss of $63.9 million for the three months ended December 31, 2013. For the year ended December 31, 2014, the non-taxable loss was $184.2 million compared to a non-taxable loss of $106.9 million for the year ended December 31, 2013.

- As at December 31, 2014, the Corporation had not recognized the tax benefit related to $273.7 million of unrealized taxable capital foreign exchange losses ($86.0 million at December 31, 2013).

- Stock-based compensation expense for the three months ended December 31, 2014 was $12.7 million compared to $9.7 million for the three months ended December 31, 2013. Stock-based compensation expense for the year ended December 31, 2014 was $48.3 million compared to $38.8 million for the year ended December 31, 2013. In addition, a deferred tax recovery of $13.8 million was recognized in the three months and year ended December 31, 2014 relating to the tax deduction available for vested Restricted Share Units. There was no tax benefit recognized in 2013 on vested Restricted Share Units.

The Corporation is not currently taxable. As of December 31, 2014, the Corporation had approximately $7.0 billion of available tax pools and had recognized a deferred income tax liability of $178.2 million. In addition, at December 31, 2014, the Corporation had $0.9 billion of capital investment in respect of incomplete projects which will increase available tax pools upon completion of the projects.

CAPITAL INVESTING

	Three months ended December 31		**Year ended December 31**	
($000)	**2014**	**2013**	**2014**	**2013**
Intraphase growth	$ 97,920	$ 23,472	$ 341,088	$ 500,472
Portfolio growth				
Christina Lake	30,364	41,856	183,396	196,359
Resource development	10,929	38,407	83,444	227,581
Growth infrastructure	16,388	42,913	84,270	412,738
Enhancements and other	34,650	4,345	74,905	43,757
Total portfolio growth	92,331	127,521	426,015	880,435
Marketing initiatives				
Access pipeline	24,145	57,837	194,867	257,629
Other	34,799	28,888	74,127	161,582
Total marketing initiatives	58,944	86,725	268,994	419,211
Sustaining and maintenance	53,234	47,072	145,272	100,309
Other	21,541	81,531	56,170	211,397
Total cash capital investment	**323,970**	**366,321**	**1,237,539**	**2,111,824**
Capitalized interest	14,901	22,911	75,975	76,529
	338,871	**389,232**	**1,313,514**	**2,188,353**
Non-cash	10,737	5,138	67,738	39,799
Total capital investment	**$ 349,608**	**$ 394,370**	**$1,381,252**	**$2,228,152**

MEG's total capital investment for the three months ended December 31, 2014 was $349.6 million (including capitalized interest of $14.9 million and non-cash items of $10.7 million) in comparison to $394.4 million (including capitalized interest of $22.9 million and non-cash items of $5.1 million) for the three months ended December 31, 2013. At September 30, 2014, the Corporation had anticipated capital investments for the fourth quarter of 2014 would be $500 million to $700 million. The $324.0 million of capital investment for the fourth quarter of 2014 was lower than anticipated primarily due to decreased activity in response to the decline in global crude oil prices.

Total capital investment for the year ended December 31, 2014 was $1.4 billion (including capitalized interest of $76.0 million and non-cash items of $67.7 million) in comparison to $2.2 billion (including capitalized interest of $76.5 million and non-cash items of $39.8 million) for the year ended December 31, 2013.

MEG invested $341.1 million during the year ended December 31, 2014 on intraphase growth, which includes RISER 2B. RISER 2B includes the application of a combination of proprietary reservoir technologies, redeployment of steam and facilities modifications, including a series of brownfield expansions of the existing Phase 2B facilities.

The Corporation invested $183.4 million in portfolio growth for Christina Lake during 2014 for engineering, the procurement of long lead-time items and site preparation for future Christina Lake expansions.

Resource development investment of $83.4 million during 2014 included the drilling of stratigraphic wells to support horizontal well placement and to further delineate the resource base at Christina Lake, Surmont and the Growth Properties.

A total of $84.3 million was invested in the Corporation's growth infrastructure during 2014. Growth infrastructure investment was primarily directed towards the construction of a sulphur recovery plant at Christina Lake, which commenced operating during the third quarter of 2014.

A total of $269.0 million was invested during 2014 in the Corporation's marketing initiatives. The majority of the investment in marketing initiatives related to the expansion of the 50%-owned Access Pipeline. The expansion for the 300-kilometer pipeline was placed into service in the third quarter of 2014.

A total of $145.3 million was invested during 2014 for sustaining and maintenance capital and primarily represents costs related to sustaining SAGD well pairs and well pads.

The Corporation capitalizes interest associated with qualifying assets. A total of $14.9 million in interest was capitalized during the three months ended December 31, 2014 compared to $22.9 million during the three months ended December 31, 2013. A total of $76.0 million of interest was capitalized during the year ended December 31, 2014 compared to $76.5 million for the year ended December 31, 2013.

Non-cash capital investment for the three months ended December 31, 2014 included a $7.0 million increase in the provision for future reclamation and decommissioning of the Corporation's property, plant and equipment and $3.7 million in capitalized stock-based compensation. Non-cash capital investment for the year ended December 31, 2014 included a $45.0 million provision for future reclamation and decommissioning and $14.2 million in capitalized stock-based compensation.

NON-GAAP MEASUREMENTS

Certain financial measures in this document including: Net marketing activity, Cash flow from operations, Operating earnings and Operating cash flow are non-GAAP measures. These terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS.

Net Marketing Activity

Net marketing activity is a non-GAAP measure which the Corporation uses to analyze the returns on the sale of third-party crude oil and related products and the costs related to transportation and storage arrangements. Net Marketing Activity represents the Corporation’s third-party petroleum sales less the cost of purchased product, related transportation and storage. Petroleum sales – third party is disclosed in Note 16 in the Notes to Interim Consolidated Financial Statements and Purchased product and storage is presented as a line item on the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss).

Cash Flow from Operations

Cash flow from operations is a non-GAAP measure utilized by the Corporation to analyze operating performance and liquidity. Cash flow from operations excludes the net change in non-cash operating working capital, non-recurring contract cancellation costs and decommissioning expenditures while the IFRS measurement "Net cash provided by (used in) operating activities" includes these items. Cash flow from Operations is reconciled to Net cash provided by (used in) operating activities in the table below.

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Net cash provided by (used in) operating activities	$ 209,985	$ 3,604	$ 767,500	$ 125,768
Add (deduct):				
Net change in non-cash operating working capital items	(93,313)	18,709	5,610	123,461
Non-recurring contract cancellation costs	16,455	-	16,455	-
Decommissioning expenditures	972	335	1,893	4,195
Cash flow from operations	$ 134,099	$ 22,648	$ 791,458	$ 253,424

Operating Earnings

Operating earnings is a non-GAAP measure which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. Operating earnings is defined as net earnings (loss) as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial liabilities, unrealized fair value gains and losses on other assets, non-recurring contract cancellation costs and the respective deferred tax impact of these adjustments. Operating earnings is reconciled to "Net loss", the nearest IFRS measure, in the table below.

	Three months ended December 31		Year ended December 31	
($000)	**2014**	**2013**	**2014**	**2013**
Net loss	$ (150,076)	$ (148,182)	$ (105,538)	$ (166,405)
Add (deduct):				
Unrealized loss on foreign exchange(1)	139,009	112,425	333,149	177,362
Unrealized loss (gain) on derivative financial liabilities(2)	5,444	(1,938)	(1,469)	(19,256)
Unrealized fair value loss (gain) on other assets(3)	-	919	(429)	-
Contract cancellation costs(4)	16,455	-	16,455	-
Deferred tax expense (recovery) relating to these adjustments	(2,748)	4,091	5,185	8,685
Operating earnings (loss)	$ 8,084	$ (32,685)	$ 247,353	$ 386

(1) *Unrealized foreign exchange gains and losses result from the translation of U.S. dollar denominated long-term debt and cash and cash equivalents using period-end exchange rates.*

(2) *Unrealized gains and losses on derivative financial liabilities result from the interest rate floor on the Corporation's long-term debt and interest rate swaps entered into to effectively fix a portion of its variable rate long-term debt.*

(3) *Unrealized fair value loss (gain) on other assets results from the fair market valuation of the other assets held at December 31, 2014 and 2013.*

(4) *Non-recurring costs relating to field asset construction contract cancellation as a result of the reduction of the Corporation's capital program for 2015.*

Operating Cash Flow

Operating cash flow is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of the Corporation's efficiency and its ability to fund future capital investments. Operating cash flow is calculated by deducting the related diluent, transportation, field operating costs and royalties from proprietary production revenues and power revenue. The per-unit calculation of Operating Cash Flow defined as Cash Operating Netback is calculated by dividing related production revenue, costs and royalties by bitumen sales volumes.

ADVISORY

Forward-Looking Information

This document may contain forward-looking information including but not limited to: expectations of future production, revenues, expenses, cash flow, operating costs, steam-oil ratios ("SORs"), pricing differentials, reliability, profitability and capital investments; estimates of reserves and resources; the anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and the anticipated sources of funding for operations and capital investments. Such forward-looking information is based on management's expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures, plans for and results of drilling activity, environmental matters, business prospects and opportunities.

By its nature, such forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: risks associated with the oil and gas industry, for example, the securing of adequate supplies and access to markets and transportation infrastructure; the availability of capacity on the electrical transmission grid; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and revenues; health, safety and environmental risks; risks of legislative and regulatory changes to, amongst other things, tax, land use, royalty and environmental laws; assumptions regarding and the volatility of commodity prices and foreign exchange rates; risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with MEG's future phases and the expansion and/or operation of MEG's projects; risks and uncertainties related to the timing of completion, commissioning, and start-up, of MEG's future phases, expansions and projects; and the operational risks and delays in the development, exploration, production, and capacities and performance associated with MEG's projects.

Although MEG believes that the assumptions used in such forward-looking information are reasonable, there can be no assurance that such assumptions will be correct. Accordingly, readers are cautioned that the actual results achieved may vary from the forward-looking information provided herein and that the variations may be material. Readers are also cautioned that the foregoing list of assumptions, risks and factors is not exhaustive.

Further information regarding the assumptions and risks inherent in the making of forward-looking statements can be found in MEG's annual information form ("AIF") dated March 5, 2014, along with MEG's other public disclosure documents. Copies of the AIF and MEG's other public disclosure documents are available through the SEDAR website which is available at www.sedar.com.

The forward-looking information included in this document is expressly qualified in its entirety by the foregoing cautionary statements. Unless otherwise stated, the forward-looking information included in this document is made as of the date of this document and the Corporation assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

Non-GAAP Financial Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS including: Net marketing activity, Cash flow from operations, Operating earnings and Operating cash flow. As such, these measures are considered non-GAAP financial measures. These terms are not defined by IFRS and, therefore, may not be comparable to similar measures provided by other companies. These non-GAAP financial measures should not be considered in isolation or as an alternative for measures of performance prepared in accordance with IFRS. These measures are presented and described in order to provide shareholders and potential investors with additional measures in understanding the Corporation's ability to generate funds and to finance its operations as well as profitability measures specific to the oil sands industry. The definition and reconciliation of each non-GAAP measure is presented in the "NON-GAAP MEASUREMENTS" section of this document.

ADDITIONAL INFORMATION

Additional information relating to the Corporation, including its AIF, is available on MEG's website at www.megenergy.com and is also available on SEDAR at www.sedar.com.

QUARTERLY SUMMARIES

	2014				2013			
Unaudited	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
FINANCIAL ($000 unless specified)								
Net earnings (loss)[1]	(150,076)	(100,975)	248,954	(103,441)	(148,182)	115,383	(62,312)	(71,294)
Per share, diluted	(0.67)	(0.45)	1.11	(0.46)	(0.67)	0.51	(0.28)	(0.32)
Operating earnings (loss)	8,084	87,471	111,139	40,659	(32,685)	56,171	13,612	(36,712)
Per share, diluted	0.04	0.39	0.49	0.18	(0.15)	0.25	0.06	(0.16)
Cash flow from operations	134,099	238,659	261,713	156,987	22,648	144,521	79,184	7,071
Per share, diluted	0.60	1.06	1.16	0.70	0.10	0.64	0.35	0.03
Cash capital investment	323,970	291,309	298,727	323,533	366,321	454,589	635,616	655,298
Cash, cash equivalents and short-term investments	656,097	776,522	839,870	890,335	1,179,072	647,096	1,203,457	1,803,338
Working capital	525,534	747,928	805,742	877,069	1,045,607	365,676	731,290	1,298,955
Long-term debt	4,365,502	4,217,536	4,016,257	4,162,209	4,004,575	2,857,740	2,923,382	2,823,207
Shareholders' equity	4,768,235	4,894,444	4,970,144	4,705,966	4,788,430	4,919,407	4,771,616	4,817,253
BUSINESS ENVIRONMENT								
West Texas Intermediate (WTI) US$/bbl	73.15	97.16	102.99	98.68	97.43	105.83	94.22	94.37
C$ equivalent of 1US$ - average	1.1357	1.0893	1.0905	1.1035	1.0477	1.0385	1.0233	1.0089
Differential – WTI vs blend ($/bbl)	19.50	27.24	27.04	31.93	41.48	23.50	26.17	39.96
Differential – WTI vs blend (%)	23.5%	25.7%	24.1%	29.3%	40.6%	21.4%	27.1%	41.9%
Natural gas – AECO ($/mcf)	3.58	4.00	4.70	5.69	3.52	2.42	3.51	3.18
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	80,349	76,471	68,984	58,643	42,251	34,246	32,144	32,531
Bitumen sales – bbls/d	70,116	69,757	70,849	58,089	35,990	32,175	32,175	32,393
Diluent usage – bbls/d	31,190	28,753	31,617	28,797	16,680	13,032	14,176	16,239
Blend sales – bbls/d	101,306	98,510	102,446	86,886	52,670	47,288	46,351	48,632
Steam to oil ratio (SOR)	2.5	2.5	2.4	2.5	2.9	2.5	2.3	2.5
Blend sales	63.57	78.60	85.27	76.96	60.60	86.40	70.25	55.24
Cost of diluent	(13.09)	(13.48)	(12.52)	(14.68)	(22.38)	(12.07)	(16.27)	(25.20)
Bitumen realization	50.48	65.12	72.75	62.28	38.22	74.33	53.98	30.04
Transportation – net	(1.82)	(1.09)	(1.80)	(0.67)	(0.51)	(0.20)	(0.17)	(0.12)
Royalties	(2.97)	(5.02)	(5.01)	(4.47)	(2.71)	(5.14)	(3.03)	(1.58)
Operating costs – non-energy	(6.42)	(7.16)	(9.64)	(9.05)	(8.09)	(9.20)	(10.00)	(8.81)
Operating costs – energy	(5.16)	(5.58)	(6.45)	(8.43)	(5.38)	(3.32)	(4.85)	(4.93)
Power revenue	1.45	2.43	1.60	3.85	2.25	3.12	6.00	3.30
Cash operating netback	**35.56**	**48.70**	**51.45**	**43.51**	**23.78**	**59.59**	**41.93**	**17.90**
Power sales price (C$/MWh)	31.67	59.07	40.98	62.26	44.63	75.96	138.96	59.92
Power sales (MW/h)	134	119	115	150	76	59	58	74
Depletion and depreciation rate per bbl	15.61	15.26	15.30	15.54	15.56	15.54	15.11	15.24
COMMON SHARES								
Shares outstanding, end of period (000)	223,847	223,794	223,673	222,575	222,507	222,489	221,829	221,256
Volume traded (000)	94,588	30,649	70,199	32,102	33,400	28,403	43,789	28,495
Common share price ($)								
High	34.69	40.75	41.29	37.84	36.00	36.69	32.98	35.67
Low	13.30	34.00	35.52	29.41	28.60	28.81	25.50	30.89
Close (end of period)	19.55	34.38	38.89	37.36	30.61	35.54	28.83	32.61

(1) Includes unrealized foreign exchange gains and losses on translation of U.S. dollar denominated debt.

Interim Consolidated Financial Statements

Consolidated Balance Sheet
(Unaudited, expressed in thousands of Canadian dollars)

As at December 31	**Note**		**2014**		2013
Assets					
Current assets					
Cash and cash equivalents	23	**$**	**656,097**	$	1,179,072
Trade receivables and other	6		**177,219**		186,183
Inventories	7		**153,320**		129,943
			986,636		1,495,198
Non-current assets					
Property, plant and equipment, net	8		**8,195,490**		7,254,951
Exploration and evaluation assets	9		**588,526**		579,497
Other intangible assets, net	10		**83,090**		63,205
Other assets	11		**76,366**		54,890
Total assets		**$**	**9,930,108**	$	9,447,741
Liabilities					
Current liabilities					
Accounts payable and accrued liabilities	12	**$**	**427,910**	$	416,288
Current portion of long-term debt	13		**15,081**		13,827
Current portion of provisions and other liabilities	14		**18,111**		19,477
			461,102		449,592
Non-current liabilities					
Long-term debt	13		**4,350,421**		3,990,748
Provisions and other liabilities	14		**172,154**		125,177
Deferred income tax liability			**178,196**		93,794
Total liabilities			**5,161,873**		4,659,311
Commitments and contingencies	26				
Shareholders' equity					
Share capital	15		**4,797,853**		4,751,374
Contributed surplus	15		**153,837**		126,666
Deficit	15		**(196,670)**		(92,493)
Accumulated other comprehensive income			**13,215**		2,883
Total shareholders' equity			**4,768,235**		4,788,430
Total liabilities and shareholders' equity		**$**	**9,930,108**	$	9,447,741

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss)
(Unaudited, expressed in thousands of Canadian dollars, except per share amounts)

		Three months ended December 31		Year ended December 31	
	Note	**2014**	2013	**2014**	2013
Petroleum revenue, net of royalties	16	**$ 598,138**	$ 338,832	**$2,743,987**	$1,270,757
Other revenue	17	**16,652**	11,506	**85,977**	63,740
		614,790	350,338	**2,829,964**	1,334,497
Diluent and transportation	18	**285,897**	172,828	**1,228,079**	623,648
Purchased product and storage	19	**30,862**	55,285	**163,387**	104,115
Operating expenses		**74,653**	44,602	**351,534**	167,586
Depletion and depreciation	8,10	**100,722**	51,508	**378,544**	189,147
General and administrative		**34,521**	22,662	**111,366**	92,828
Stock-based compensation	15	**12,746**	9,660	**48,310**	38,792
Research and development		**2,197**	1,645	**6,003**	5,588
		541,598	358,190	**2,287,223**	1,221,704
Revenues less expenses		**73,192**	(7,852)	**542,741**	112,793
Other income (expense)					
Interest and other income		**1,762**	7,986	**9,107**	22,550
Gain on disposition of assets		**-**	1,410	**-**	1,410
Foreign exchange loss, net	20	**(140,790)**	(113,605)	**(338,629)**	(180,278)
Net finance expense	21	**(62,124)**	(38,978)	**(196,858)**	(100,533)
Other expenses	22	**(36,123)**	-	**(36,123)**	-
		(237,275)	(143,187)	**(562,503)**	(256,851)
Loss before income taxes		**(164,083)**	(151,039)	**(19,762)**	(144,058)
Deferred income tax expense (recovery)		**(14,007)**	(2,857)	**85,776**	22,347
Net loss		**(150,076)**	(148,182)	**(105,538)**	(166,405)
Other comprehensive income, net of tax					
Items that may be reclassified into profit or loss:					
Foreign currency translation adjustment		**5,600**	3,039	**10,332**	2,858
Comprehensive loss for the period		**$ (144,476)**	$ (145,143)	**$ (95,206)**	$ (163,547)
Net loss per share					
Basic	24	**$ (0.67)**	$ (0.67)	**$ (0.47)**	$ (0.75)
Diluted	24	**$ (0.67)**	$ (0.67)	**$ (0.47)**	$ (0.75)

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Changes in Shareholders' Equity
(Unaudited, expressed in thousands of Canadian dollars)

	Note	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance at January 1, 2014		**$ 4,751,374**	**$ 126,666**	**$ (92,493)**	**$ 2,883**	**$ 4,788,430**
Stock options exercised	15	**14,665**	**(3,499)**	**-**	**-**	**11,166**
RSUs vested and released	15	**31,814**	**(31,814)**	**1,361**	**-**	**1,361**
Stock-based compensation	15	**-**	**62,484**	**-**	**-**	**62,484**
Net loss		**-**	**-**	**(105,538)**	**-**	**(105,538)**
Other comprehensive income		**-**	**-**	**-**	**10,332**	**10,332**
Balance at December 31, 2014		**$ 4,797,853**	**$ 153,837**	**$ (196,670)**	**$ 13,215**	**$ 4,768,235**
Balance at January 1, 2013		$ 4,694,378	$ 102,219	$ 73,912	$ 25	$ 4,870,534
Share issue costs, net of tax		79	-	-	-	79
Stock options exercised	15	40,522	(9,217)	-	-	31,305
RSUs vested and released	15	16,395	(16,395)	-	-	-
Stock-based compensation	15	-	50,059	-	-	50,059
Net loss		-	-	(166,405)	-	(166,405)
Other comprehensive income		-	-	-	2,858	2,858
Balance at December 31, 2013		$ 4,751,374	$ 126,666	$ (92,493)	$ 2,883	$ 4,788,430

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

Consolidated Statement of Cash Flow
(Unaudited, expressed in thousands of Canadian dollars)

		Three months ended December 31		Year ended December 31	
	Note	**2014**	2013	**2014**	2013
Cash provided by (used in):					
Operating activities					
Net loss		**$ (150,076)**	$ (148,182)	**$ (105,538)**	$ (166,405)
Adjustments for:					
Depletion and depreciation		**100,722**	51,508	**378,544**	189,147
Stock-based compensation		**12,746**	9,660	**48,310**	38,792
Unrealized loss on foreign exchange	20	**139,009**	112,425	**333,149**	177,362
Unrealized loss (gain) on derivative financial liabilities	21	**5,444**	(1,938)	**(1,469)**	(19,256)
Inventory write-down	7,22	**19,668**	-	**19,668**	-
Deferred income tax expense (recovery)		**(14,007)**	(2,857)	**85,776**	22,347
Amortization of debt issue costs	11,13	**2,936**	1,552	**10,566**	8,840
Decommissioning expenditures	14	**(972)**	(335)	**(1,893)**	(4,195)
Other		**1,202**	480	**5,997**	2,597
Net change in non-cash operating working capital items	23	**93,313**	(18,709)	**(5,610)**	(123,461)
Net cash provided by (used in) operating activities		**209,985**	3,604	**767,500**	125,768
Investing activities					
Capital Investments					
Property, plant and equipment	8	**(325,259)**	(381,854)	**(1,282,194)**	(2,142,510)
Exploration and evaluation	9	**(1,199)**	(885)	**(7,749)**	(27,123)
Other intangible assets	10	**(12,413)**	(6,493)	**(23,571)**	(18,720)
Disposition (purchase) of other assets	11	**(1,358)**	373	**(1,358)**	(41,517)
Proceeds on disposition of assets		**-**	6,801	**-**	6,801
Other		**3,676**	2,761	**5,778**	2,773
Net change in non-cash investing working capital items	23	**8,601**	39,015	**(3,346)**	430,316
Net cash provided by (used in) investing activities		**(327,952)**	(340,282)	**(1,312,440)**	(1,789,980)
Financing activities					
Issue of shares		**436**	330	**11,166**	31,747
Issue of long-term debt, net of debt issue costs		**-**	1,021,418	**-**	1,322,540
Repayment of long-term debt		**(3,769)**	(3,457)	**(14,467)**	(13,506)
Financing costs	11	**(10,035)**	-	**(10,035)**	(8,693)
Net cash provided by (used in) financing activities		**(13,368)**	1,018,291	**(13,336)**	1,332,088
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	20	**10,910**	15,409	**35,301**	36,353
Change in cash and cash equivalents		**(120,425)**	697,022	**(522,975)**	(295,771)
Cash and cash equivalents, beginning of period		**776,522**	482,050	**1,179,072**	1,474,843
Cash and cash equivalents, end of period		**$ 656,097**	$ 1,179,072	**$ 656,097**	$ 1,179,072

The accompanying notes are an integral part of these Interim Consolidated Financial Statements.

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MEG". The Corporation owns a 100% interest in over 900 sections of oil sands leases in the Athabasca oil sands region of northern Alberta and is primarily engaged in a steam assisted gravity drainage oil sands development at its 80 section Christina Lake Regional Project ("Christina Lake project"). The Corporation is using a staged approach to development. The Corporation also holds a 50% interest in the Access Pipeline, a dual pipeline to transport diluent north from the Edmonton area to the Athabasca oil sands area and a blend of bitumen and diluent south from the Christina Lake project into the Edmonton area. In addition to the Access Pipeline, the Corporation owns the Stonefell Terminal, located near Edmonton, Alberta, which offers 900,000 barrels of terminalling and storage capacity. The Stonefell Terminal is connected to the Access Pipeline and is also connected by pipeline to a third party rail-loading terminal. The corporate office is located at 520 - 3rd Avenue S.W., Calgary, Alberta, Canada.

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements (“interim consolidated financial statements”) were prepared using the same accounting policies and methods as those used in the Corporation’s audited financial statements for the year ended December 31, 2013, except as described in Note 3 below. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting (“IAS 34”). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board ("IASB"), have been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation’s accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 3 of the Corporation’s audited financial statements for the year ended December 31, 2013. These interim consolidated financial statements should be read in conjunction with the Corporation’s audited financial statements for the year ended December 31, 2013, which are included in the Corporation’s 2013 annual report.

These interim consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation’s functional currency. The Corporation’s operations are aggregated into one operating segment for reporting consistent with the internal reporting provided to the chief operating decision-maker of the Corporation.

These interim consolidated financial statements were approved by the Corporation’s Audit Committee on February 4, 2015.

3. CHANGE IN ACCOUNTING POLICIES

The Corporation has adopted the following revised standards effective January 1, 2014. These changes, along with all the consequential amendments, are made in accordance with the applicable transitional provisions. The adoption of these revisions did not have an impact on the Corporation's consolidated financial statements.

IAS 32, Financial Instruments: Presentation, has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

IAS 36, Impairment of Assets, has been amended to require additional disclosures in the event of recognizing an impairment of assets.

Accounting standards issued but not yet applied

IFRS 15, Revenue From Contracts With Customers, provides clarification for recognizing revenue from contracts with customers and establishes a single revenue recognition and measurement framework that applies to contracts with customers. The new standard is effective for annual periods beginning on or after January 1, 2017, with early adoption permitted. The Corporation is currently assessing the impact of the adoption of IFRS 15 on the Corporation's consolidated financial statements.

IFRS 9, Financial Instruments, is intended to replace IAS 39, Financial Instruments: Recognition and Measurement and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. For financial liabilities designated at fair value through profit or loss, a corporation can recognize the portion of the change in fair value related to the change in the corporation's own credit risk through other comprehensive income rather than net earnings. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The Corporation is currently assessing the impact of the adoption of IFRS 9 on the Corporation's consolidated financial statements.

4. PRINCIPLES OF CONSOLIDATION

The interim consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc. All intercompany transactions and balances are eliminated on consolidation.

The Corporation accounts for its undivided 50% interest in Access Pipeline as a joint operation. The Corporation's interest in the Access Pipeline is included in the consolidated financial statements in proportion to the Corporation's share of assets, liabilities, revenues and expenses.

5. FINANCIAL INSTRUMENTS AND DERIVATIVE FINANCIAL LIABILITIES

The financial instruments recognized on the Consolidated Balance Sheet are comprised of cash and cash equivalents, trade receivables and other, U.S. auction rate securities ("ARS") within other assets, accounts payable and accrued liabilities, derivative financial liabilities and long-term debt. As at December 31, 2014, ARS and derivative financial liabilities were classified as held-for-trading financial instruments; cash and cash equivalents and trade receivables and other were classified as loans and receivables; and accounts payable and accrued liabilities were classified as other financial liabilities. Long-term debt was carried at amortized cost.

The carrying value of cash and cash equivalents, trade receivables and other, and accounts payable and accrued liabilities included on the Consolidated Balance Sheet approximate fair value due to the short-term nature of those instruments.

(a) Fair value measurement of ARS, derivative financial liabilities and long-term debt

			Fair value measurements using		
As at December 31, 2014	**Carrying amount**	**Fair value**	**Quoted prices in active markets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
Recurring measurements:					
Financial assets					
ARS (note 11)	**$ 2,908**	**$ 2,908**	**$ -**	**$ 2,908**	**$ -**
Financial liabilities					
Derivative financial liabilities (note 14)	**29,511**	**29,511**	**-**	**29,511**	**-**
Long-term debt (note 13)[1]	**4,421,721**	**4,075,233**	**4,075,233**	**-**	**-**

			Fair value measurements using		
As at December 31, 2013	Carrying amount	Fair value	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Recurring measurements:					
Financial assets					
ARS (note 11)	$ 2,252	$ 2,252	$ -	$ -	$ 2,252
Financial liabilities					
Derivative financial liabilities (note 14)	30,981	30,981	-	30,981	-
Long-term debt (note 13) [1]	4,067,738	4,135,639	4,135,639	-	-

(1) Long-term debt includes the current and long-term portions.

Level 1 fair value measurements are based on unadjusted quoted market prices.

The fair value of long-term debt is derived using quoted prices in an active market.

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted prices or indices.

The fair value of derivative financial liabilities are derived using third-party valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates for the Corporation's interest rate swaps and floors. Management's assumptions rely on external observable market data including interest rate yield curves. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.

Other assets are comprised of investments in U.S. auction rate securities (“ARS”). The estimated fair value of the ARS is derived using quoted prices in an inactive market from a third-party independent broker.

Level 3 fair value measurements are based on unobservable information.

Level 3 measurements consist of financial instruments with a fair value that is determined by reference to prices with significant unobservable inputs. As at December 31, 2014, the Corporation does not have any financial instruments measured at Level 3 fair value.

The Corporation recognizes transfers into and transfers out of fair value hierarchy levels as of the date of the event or change in circumstances that caused the transfer. In September 2014, the fair value measurement of ARS, in the amount of $2.9 million, was transferred from Level 3 to Level 2 as a result of the Corporation’s ability to obtain independent market corroborated data.

During the year ended December 31, 2014, an unrealized gain of $0.4 million was recognized within net finance expense to recognize a change in fair value of ARS (December 31, 2013 – $0.1 million).

(b) Interest rate risk management

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. As noted below, in order to mitigate a portion of this risk, the Corporation has entered into interest rate swap contracts to effectively fix the interest rate on US$748.0 million of the US$1.3 billion senior secured term loan. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise. As at December 31, 2014, the Corporation has recognized an $8.7 million derivative financial liability related to these interest rate swaps (December 31, 2013 - $7.5 million).

Amount	Effective date	Remaining term	Fixed rate	Floating rate
US$300 million	September 30, 2011	Jan 2015-Sept 2016	4.436%	3 month LIBOR[1]
US$150 million	December 31, 2011	Jan 2015-Sept 2016	4.376%	3 month LIBOR[1]
US$150 million	January 12, 2012	Jan 2015-Sept 2016	4.302%	3 month LIBOR[1]
US$148 million	January 27, 2012	Jan 2015-Sept 2016	4.218%	3 month LIBOR[1]

[1] *London Interbank Offered Rate*

6. TRADE RECEIVABLES AND OTHER

As at December 31		2014		2013
Trade receivables	**$**	**167,559**	$	174,935
Deposits and advances		**5,344**		7,908
Current portion of deferred financing costs		**4,316**		3,340
	$	**177,219**	$	186,183

7. INVENTORIES

As at December 31		2014		2013
Diluent	**$**	**83,001**	$	84,628
Bitumen blend		**68,273**		43,358
Materials and supplies		**2,046**		1,957
	$	**153,320**	$	129,943

During the year ended December 31, 2014, a total of $1,163.6 million in inventory product costs were charged to earnings through diluent and transportation expense (year ended December 31, 2013 - $601.2 million).

During the three months and year ended December 31, 2014, the Corporation recognized a $19.7 million bitumen blend inventory write-down to net realizable value as a result of the recent decline in global crude oil prices.

8. PROPERTY, PLANT AND EQUIPMENT

		Crude oil		Transportation and storage		Corporate assets		Total
Cost								
Balance as at December 31, 2012	$	4,799,595	$	793,671	$	33,597	$	5,626,863
Additions[1]		1,694,070		480,263		7,438		2,181,771
Transfer from exploration and evaluation assets (note 9)		-		2,513		-		2,513
Balance as at December 31, 2013	$	6,493,665	$	1,276,447	$	41,035	$	7,811,147
Additions[1]		1,045,704		296,248		6,082		1,348,034
Transfer to other assets (note 11)		-		(12,381)		-		(12,381)
Balance as at December 31, 2014	**$**	**7,539,369**	**$**	**1,560,314**	**$**	**47,117**	**$**	**9,146,800**

		Crude oil		Transportation and storage		Corporate assets		Total
Accumulated depletion and depreciation								
Balance as at December 31, 2012	$	329,556	$	22,831	$	6,591	$	358,978
Depletion and depreciation for the year[2]		183,866		8,621		4,731		197,218
Balance as at December 31, 2013	$	513,422	$	31,452	$	11,322	$	556,196
Depletion and depreciation for the year[2]		370,301		19,661		5,152		395,114
Balance as at December 31, 2014	**$**	**883,723**	**$**	**51,113**	**$**	**16,474**	**$**	**951,310**

		Crude oil		Transportation and storage		Corporate assets		Total
Carrying Amounts								
As at December 31, 2013	$	5,980,243	$	1,244,995	$	29,713	$	7,254,951
As at December 31, 2014	**$**	**6,655,646**	**$**	**1,509,201**	**$**	**30,643**	**$**	**8,195,490**

(a) Non-cash additions during the year ended December 31, 2014 included $43.7 million for future reclamation and decommissioning, $14.2 million in capitalized stock-based compensation and $7.9 million of other non-cash items. During the year ended December 31, 2013, non-cash additions included $25.5 million for future reclamation and decommissioning, $11.3 million in capitalized stock-based compensation and $2.5 million of other non-cash items.

(b) Depletion and depreciation during the year ended December 31, 2014 included $20.3 million capitalized as linefill or transferred to inventory. During the year ended December 31, 2013, depletion and depreciation included $9.6 million capitalized or transferred to inventory.

During the year ended December 31, 2014, the Corporation capitalized $34.6 million (year ended December 31, 2013 - $30.4 million) of general and administrative costs relating to oil sands exploration and development activities. In addition, $74.7 million of interest and finance charges related to the development of capital projects were capitalized during the year ended December 31, 2014 (year ended December 31, 2013 - $75.3 million). As at December 31, 2014, $749.1 million of assets under construction were included within property, plant and equipment (December 31, 2013

- $947.6 million). Assets under construction are not subject to depletion and depreciation. As of December 31, 2014, no impairment has been recognized on these assets.

9. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2012	$	554,349
Additions[(1)]		27,661
Transfer to property, plant and equipment (note 8)		(2,513)
Balance as at December 31, 2013	$	579,497
Additions[(1)]		9,029
Balance as at December 31, 2014	**$**	**588,526**

(1) Additions included $1.3 million for future reclamation and decommissioning during the year ended December 31, 2014 and $0.5 million for the year ended December 31, 2013.

Exploration and evaluation assets consist of exploration projects which are pending the determination of proved or probable reserves. These assets are not subject to depletion, as they are in the exploration and evaluation stage, but are reviewed on a quarterly basis for any indication of impairment. As of December 31, 2014, no impairment has been recognized on these assets. During the year ended December 31, 2014, the Corporation capitalized $1.3 million of interest and finance charges related to exploration and evaluation assets (year ended December 31, 2013 - $1.2 million).

10. OTHER INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2012	$	47,489
Additions		18,720
Balance as at December 31, 2013	$	66,209
Additions		23,571
Balance as at December 31, 2014	**$**	**89,780**

Accumulated depreciation		
Balance as at December 31, 2012	$	1,456
Depreciation		1,548
Balance as at December 31, 2013	$	3,004
Depreciation		3,686
Balance as at December 31, 2014	**$**	**6,690**

Carrying Amounts		
As at December 31, 2013	$	63,205
As at December 31, 2014	**$**	**83,090**

At December 31, 2014, other intangible assets include $60.2 million invested to maintain the right to participate in a potential pipeline project and $22.9 million invested in software that is not an integral component of the related computer hardware (December 31, 2013 - $52.1 million, and $11.1 million respectively). As of December 31, 2014, no impairment has been recognized on these assets.

11. OTHER ASSETS

As at December 31		2014		2013
Long-term pipeline linefill[a]	**$**	**56,900**	$	41,517
ARS[b]		**2,908**		2,252
Deferred financing costs[c]		**20,874**		14,461
		80,682		58,230
Less current portion of deferred financing costs		**(4,316)**		(3,340)
	$	**76,366**	$	54,890

(a) In 2013, the Corporation entered into an agreement to transport diluent on a third-party pipeline and was required to supply diluent linefill for the pipeline. The Corporation purchased this diluent, which is carried at the lower of cost or net realizable value. In 2014, the Corporation entered into an agreement to transport bitumen blend on a third-party pipeline and is required to supply bitumen blend linefill. The Corporation is fulfilling this commitment through the transfer of bitumen blend linefill from the Access Pipeline. During 2014, the Corporation transferred, at carrying cost, $12.4 million of Access Pipeline linefill from property, plant and equipment to other assets. The linefill is carried at the lower of cost or net realizable value.

As these pipelines are owned by third parties, the linefill is not considered to be a component of the Corporation's property, plant and equipment. The linefill is classified as a long-term asset as these transportation contracts extend beyond the year 2025. As of December 31, 2014, no impairment has been recognized on these assets.

(b) The investment in ARS is considered a long-term asset and is recorded at its fair value based on quoted prices in an inactive market from a third party independent broker. Changes in fair value are included in net finance expense in the period in which they arise.

(c) Costs associated with establishing the Corporation’s revolving credit facility are deferred and amortized over the term of the credit facility. During the fourth quarter of 2014, the Corporation incurred $10.0 million of costs associated with amendments to the senior secured credit facility and the establishment of a credit facility guaranteed by Export Development Canada (“EDC”). These costs have been deferred and are being amortized over the respective lives of the facilities (note 13).

12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31		2014		2013
Trade payables	**$**	**10,810**	$	33,974
Accrued and other liabilities		**355,564**		325,750
Interest payable		**61,536**		56,564
	$	**427,910**	$	416,288

13. LONG-TERM DEBT

As at December 31		2014		2013
Senior secured term loan (December 31, 2014 – US$1.262 billion; December 31, 2013 – US$1.275 billion)[(a)]	**$**	**1,463,466**	$	1,355,558
6.5% senior unsecured notes (US$750 million)[(b)]		**870,075**		797,700
6.375% senior unsecured notes (US$800 million)[(c)]		**928,080**		850,880
7.0% senior unsecured notes (US$1.0 billion)[(d)]		**1,160,100**		1,063,600
		4,421,721		4,067,738
Less:				
Current portion of senior secured term loan		**(15,081)**		(13,827)
Unamortized financial derivative liability discount		**(17,514)**		(20,565)
Unamortized deferred debt issue costs		**(38,705)**		(42,598)
	$	**4,350,421**	$	3,990,748

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.1601 (December 31, 2013 - US$1 = C$1.0636).

All of the Corporation's long-term debt is "covenant lite" in structure, meaning it is free of any financial maintenance covenants and is not dependent on, nor calculated from, the Corporation's crude oil reserves. The first maturity of any of the Corporation's long-term debt obligations is March 2020.

(a) On February 25, 2013, the Corporation re-priced, increased and extended its existing US$987.5 million senior secured term loan. The Corporation extended the maturity date to March 31, 2020 and increased its borrowing under the senior secured term loan by US$300.0 million. In addition, the Corporation reduced the interest rate on the term loan by 25 basis points.

Effective November 5, 2014, the Corporation agreed to expand its senior secured revolving credit facility from US$2.0 billion to US$2.5 billion and has extended the maturity of the revolving credit facility to November 5, 2019. As at December 31, 2014, the revolving credit facility remains undrawn.

The senior secured credit facilities are comprised of a US$1.262 billion term loan and a US$2.5 billion revolving credit facility. The senior secured credit facilities are secured by substantially all the assets of the Corporation. The term loan bears a floating interest rate based on either U.S. Prime or LIBOR, at the Corporation's option, plus a credit spread of 175 or 275 basis points, respectively. The term loan also has an interest rate floor of 200 basis points based on U.S. Prime or 100 basis points based on LIBOR. The term loan is to be repaid in quarterly installment payments equal to US$3.25 million, with the balance due on March 31, 2020. Interest is paid quarterly. The Corporation has deferred the associated remaining debt issue costs of $5.2 million and is amortizing these costs over the life of the loan utilizing the effective interest method.

Effective December 15, 2014, the Corporation entered into a five-year US$500.0 million guaranteed letter of credit facility guaranteed by EDC. The facility matures on November 5, 2019. Letters of credit issued under this facility will not consume capacity of the revolving credit facility. As at December 31, 2014, letters of credit of US$164.8 million had been issued under this facility.

(b) Effective March 18, 2011, the Corporation issued US$750.0 million in aggregate principal amount of 6.5% Senior Unsecured Notes, with a maturity date of March 15, 2021. Interest is paid semi-annually on March 15 and September 15. No principal payments are required until March 15, 2021. The Corporation has deferred the associated remaining debt issue costs of $10.1 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(c) Effective July 19, 2012, the Corporation issued US$800.0 million in aggregate principal amount of 6.375% Senior Unsecured Notes, with a maturity date of January 30, 2023. Interest is paid semi-annually on January 30 and July 30. No principal payments are required until January 30, 2023. The Corporation has deferred the associated remaining debt issue costs of $11.2 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

(d) Effective October 1, 2013, the Corporation issued US$800.0 million in aggregate principal amount of 7.0% Senior Unsecured Notes, with a maturity date of March 31, 2024. On November 6, 2013 an additional US$200 million of 7.0% Senior Unsecured Notes were issued under the same indenture. Interest is paid semi-annually on March 31 and September 30. No principal payments are required until March 31, 2024. The Corporation has deferred the associated remaining debt issue costs of $12.2 million and is amortizing these costs over the life of the notes utilizing the effective interest method.

14. PROVISIONS AND OTHER LIABILITIES

As at December 31		**2014**		2013
Derivative financial liabilities[(a)]	**$**	**29,511**	$	30,981
Decommissioning provision[(b)]		**156,382**		108,695
Deferred lease inducements[(c)]		**4,372**		4,978
Provisions and other liabilities		**190,265**		144,654
Less current portion		**(18,111)**		(19,477)
Non-current portion	**$**	**172,154**	$	125,177

(a) Derivative financial liabilities

As at December 31		**2014**		2013
1% interest rate floor	**$**	**20,844**	$	23,497
Interest rate swaps		**8,667**		7,484
Derivative financial liabilities		**29,511**		30,981
Less current portion		**(15,538)**		(13,886)
Non-current portion	**$**	**13,973**	$	17,095

The interest rate floor on the senior secured term loan has been recognized as an embedded derivative, as the floor rate exceeded the market rate of interest at the time that the debt was incurred. As a result, the interest rate floor derivative is required to be separated from the carrying value of long-term debt and accounted for as a separate derivative financial liability measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

The Corporation is exposed to interest rate risk in relation to interest income earned on cash, cash equivalents and short-term investments and in relation to interest expense on floating rate long-term debt. To mitigate a portion of the risk of interest rate increases on long-term debt, the Corporation periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. As at December 31, 2014, the Corporation had entered into interest rate swaps on US$748.0 million (note 5(b)) which expire September 30, 2016. Interest rate swaps are classified as derivative financial liabilities and measured at fair value, with gains and losses on re-measurement included in net finance expense in the period in which they arise.

(b) The following table presents the decommissioning provision associated with the reclamation and abandonment of crude oil, transportation and storage assets:

As at December 31		**2014**		2013
Decommissioning provision, beginning of year	**$**	**108,695**	$	82,087
Changes in estimated future cash flows		**20,406**		15,082
Changes in discount rates		**13,798**		(19,110)
Liabilities incurred		**10,841**		30,068
Liabilities settled		**(1,893)**		(4,195)
Accretion		**4,535**		4,763
Decommissioning provision, end of year		**156,382**		108,695
Less current portion		**(1,835)**		(4,848)
Non-current portion	**$**	**154,547**	$	103,847

The total decommissioning provision is based on the estimated costs to reclaim and abandon the Corporation's crude oil, transportation and storage assets and the estimated timing of the costs to be incurred in future years. The Corporation has estimated the net present value of the decommissioning obligations to be $156.4 million as at December 31, 2014 (December 31, 2013 - $108.7 million) based on an undiscounted total future liability of $707.8 million (December 31, 2013 - $569.5 million) and a credit-adjusted risk-free rate of 6.0% (December 31, 2013 – 6.4%). The decommissioning obligation is estimated to be settled in periods up to the year 2064.

(c) Deferred lease inducements

As at December 31		**2014**		2013
Deferred lease inducements	**$**	**4,372**	$	4,978
Less current portion		**(738)**		(743)
Non-current portion	**$**	**3,634**	$	4,235

Leasehold inducements were received when the Corporation entered into the corporate office lease. These inducements are recognized as a deferred liability and amortized through general and administrative expense over the life of the lease.

15. SHARE CAPITAL

(a) Authorized:

Unlimited number of common shares
Unlimited number of preferred shares

(b) Changes in issued common shares are as follows:

	2014			2013		
	Number of shares		**Amount**	Number of shares		Amount
Balance, beginning of year	**222,506,896**	**$**	**4,751,374**	220,190,084	$	4,694,378
Share issue costs, net of tax	**-**		**-**	-		79
Issued upon exercise of stock options	**412,644**		**14,665**	1,893,732		40,522
Issued upon vesting and release of RSUs	**927,351**		**31,814**	423,080		16,395
Balance, end of year	**223,846,891**	**$**	**4,797,853**	222,506,896	$	4,751,374

(c) Stock options outstanding:

The Corporation's stock option plan allows for the granting of options to directors, officers, employees and consultants of the Corporation. Options granted are generally fully exercisable after three years and expire seven years after the grant date.

	2014			2013		
	Stock options		**Weighted average exercise price per share**	Stock options		Weighted average exercise price per share
Outstanding, beginning of year	**8,859,028**	**$**	**35.49**	9,147,404	$	32.50
Granted	**1,790,697**		**37.64**	1,774,854		30.95
Exercised	**(412,644)**		**27.05**	(1,893,732)		16.53
Forfeited	**(332,545)**		**39.23**	(169,498)		38.19
Expired	**(2,038,748)**		**40.88**	-		-
Outstanding, end of year	**7,865,788**	**$**	**34.87**	8,859,028	$	35.49

(d) Restricted share units outstanding and performance share units outstanding:

The Restricted Share Unit Plan allows for the granting of Restricted Share Units ("RSUs"), including Performance Share Units ("PSUs"), to directors, officers, employees and consultants of the Corporation. An RSU, including a PSU, represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares. A PSU is an RSU, the vesting of which has been made conditional on the satisfaction of certain performance criteria. PSUs become eligible to vest if the Corporation satisfies the performance criteria identified by the Corporation's Board of Directors within a target range. A pre-determined multiplier is then applied to PSUs that have become eligible to vest, dependent on the point in the target range to which such performance criteria are satisfied. RSUs granted under the Restricted Share Unit Plan generally vest annually over a three year period. PSUs granted under the Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the performance criteria have been satisfied, and that the holder remains actively employed, a director or a consultant with the Corporation on the vesting date.

RSUs and PSUs outstanding	**2014**	2013
Outstanding, beginning of year	**2,589,700**	953,804
Granted	**1,173,895**	2,157,534
Vested and released	**(927,351)**	(423,080)
Forfeited	**(90,805)**	(98,558)
Outstanding, end of year	**2,745,439**	2,589,700

(e) Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of Deferred Share Units ("DSUs") to directors of the Corporation. A DSU represents the right for the holder to receive a cash payment equal to the fair market value of the Corporation's common shares calculated at the date of such payment or, at the election of the Corporation, its equivalent in fully-paid common shares purchased through a broker. DSUs are vested when they are granted and are redeemed on the third business day following the date on which the holder ceases to be a director. At December 31, 2014, there were 17,281 DSUs outstanding (December 31, 2013 – 8,874).

(f) Contributed surplus:

		2014		2013
Balance, beginning of year	**$**	**126,666**	$	102,219
Stock-based compensation - expensed		**48,310**		38,792
Stock-based compensation - capitalized		**14,174**		11,267
Stock options exercised		**(3,499)**		(9,217)
RSUs vested and released		**(31,814)**		(16,395)
Balance, end of year	**$**	**153,837**	$	126,666

16. PETROLEUM REVENUE, NET OF ROYALTIES

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Petroleum revenue:				
Proprietary	**$ 592,518**	$ 293,657	**$ 2,701,801**	$ 1,207,650
Third party[a]	**24,800**	54,154	**149,260**	101,750
	617,318	347,811	**2,851,061**	1,309,400
Royalties	**(19,180)**	(8,979)	**(107,074)**	(38,643)
Petroleum revenue, net of royalties	**$ 598,138**	$ 338,832	**$ 2,743,987**	$ 1,270,757

(a) The Corporation purchases crude oil products from third parties for marketing-related activities. These purchases and associated storage charges are included in the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss) under the caption "Purchased product and storage".

17. OTHER REVENUE

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Power revenue	**$ 9,339**	$ 7,448	**$ 55,352**	$ 44,456
Transportation revenue	**7,313**	4,058	**30,625**	19,284
Other revenue	**$ 16,652**	$ 11,506	**$ 85,977**	$ 63,740

18. DILUENT AND TRANSPORTATION

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Diluent	**$ 266,869**	$ 167,094	**$ 1,163,637**	$ 601,191
Transportation expense	**19,028**	5,734	**64,442**	22,457
Diluent and transportation	**$ 285,897**	$ 172,828	**$ 1,228,079**	$ 623,648

19. PURCHASED PRODUCT AND STORAGE

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Purchased product and storage	**$ 30,862**	$ 55,285	**$ 163,387**	$ 104,115

The Corporation purchases crude oil products from third parties for marketing-related activities. The revenue associated with these purchases and associated storage charges are included in the Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss) under the caption "Petroleum revenue, net of royalties".

20. FOREIGN EXCHANGE LOSS, NET

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Unrealized foreign exchange gain (loss) on:				
Long-term debt	**$ (149,919)**	$ (127,834)	**$ (368,450)**	$ (213,715)
US$ denominated cash and cash equivalents	**10,910**	15,409	**35,301**	36,353
Unrealized loss on foreign exchange	**(139,009)**	(112,425)	**(333,149)**	(177,362)
Realized loss on foreign exchange	**(1,781)**	(1,180)	**(5,480)**	(2,916)
Net foreign exchange loss	**$ (140,790)**	$ (113,605)	**$ (338,629)**	$ (180,278)

21. NET FINANCE EXPENSE

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Total interest expense	**$ 69,000**	$ 60,679	**$ 265,140**	$ 186,835
Less capitalized interest	**(14,901)**	(22,911)	**(75,975)**	(76,529)
Net interest expense	**54,099**	37,768	**189,165**	110,306
Accretion on decommissioning provision	**1,270**	1,017	**4,535**	4,763
Unrealized fair value loss (gain) on embedded derivative liabilities	**2,673**	(2,097)	**(2,652)**	(14,352)
Unrealized fair value loss (gain) on interest rate swaps	**2,771**	159	**1,183**	(4,904)
Realized loss on interest rate swaps	**1,311**	1,212	**5,056**	4,720
Unrealized fair value loss (gain) on other assets	**-**	919	**(429)**	-
Net finance expense	**$ 62,124**	$ 38,978	**$ 196,858**	$ 100,533

22. OTHER EXPENSES

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Inventory write-down[(a)]	**$ 19,668**	$ -	**$ 19,668**	$ -
Contract cancellation costs[(b)]	**16,455**	-	**16,455**	-
Other expenses	**$ 36,123**	$ -	**$ 36,123**	$ -

(a) During the three months and year ended December 31, 2014, the Corporation recognized a $19.7 million bitumen blend inventory write-down to net realizable value as a result of the recent decline in global crude oil prices (three months and year ended December 31, 2013 - $nil).

(b) During the three months and year ended December 31, 2014, the Corporation recognized $16.5 million in field asset construction contract cancellation costs relating to a reduction of the Corporation's capital program for 2015 (three months and year ended December 31, 2013 - $nil).

23. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Changes in non-cash working capital				
Operating activities:				
Trade receivables and other	**$ 80,105**	$ (17,651)	**$ 9,941**	$ (75,107)
Inventories[(a)]	**(26,649)**	(98,243)	**(30,519)**	(105,276)
Accounts payable and accrued liabilities	**39,857**	97,185	**14,968**	56,922
Change in operating non-cash working capital	**$ 93,313**	$ (18,709)	**$ (5,610)**	$ (123,461)
Investing activities:				
Short-term investments	**$ -**	$ 165,046	**$ -**	$ 532,998
Accounts payable and accrued liabilities	**8,601**	(126,031)	**(3,346)**	(103,711)
Trade receivables and other	**-**	-	**-**	1,029
Change in investing non-cash working capital	**$ 8,601**	$ 39,015	**$ (3,346)**	$ 430,316
Change in total non-cash working capital	**$ 101,914**	$ 20,306	**$ (8,956)**	$ 306,855
Cash and cash equivalents:[(b)]				
Cash	**$ 273,846**	$ 1,065,179	**$ 273,846**	$ 1,065,179
Cash equivalents	**382,251**	113,893	**382,251**	113,893
	$ 656,097	$ 1,179,072	**$ 656,097**	$ 1,179,072

(a) The three months and year ended December 31, 2014 amounts exclude non-cash decreases in inventory of $5.2 million and $7.1 million respectively (three months and year ended December 31, 2013 – $7.1 million).

(b) As at December 31, 2014, C$404.9 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars. (December 31, 2013 – C$566.2 million). The U.S. dollar cash and cash equivalents was translated into Canadian dollars at the year end exchange rate of US$1 = C$1.1601 (December 31, 2013 - US$1 = C$1.0636).

24. EARNINGS (LOSS) PER COMMON SHARE

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Net loss	**$ (150,076)**	$ (148,182)	**$ (105,538)**	$ (166,405)
Weighted average common shares outstanding	**223,866,119**	222,502,613	**223,314,791**	221,800,594
Dilutive effect of stock options, RSUs and PSUs[(a)]	**-**	-	**-**	-
Weighted average common shares outstanding – diluted	**223,866,119**	222,502,613	**223,314,791**	221,800,594
Net loss per share, basic	**$ (0.67)**	$ (0.67)	**$ (0.47)**	$ (0.75)
Net loss per share, diluted	**$ (0.67)**	$ (0.67)	**$ (0.47)**	$ (0.75)

(a) For the three months and year ended December 31, 2014, there was no dilutive effect of stock options, RSUs and PSUs due to the Corporation incurring a net loss during these periods. If the Corporation would have had net earnings during these periods, the dilutive effect of stock options, RSUs and PSUs would have been 801,663 for the three months ended December 31, 2014 (three months ended December 31, 2013 – 2,693,113) and 1,371,687 for the year ended December 31, 2014 (year ended December 31, 2013 - 2,508,677).

25. GEOGRAPHICAL DISCLOSURE

As at December 31, 2014, the Corporation had non-current assets related to operations in the United States of $56.9 million (December 31, 2013 - $41.5 million). For the three months and year ended December 31, 2014, petroleum revenue related to operations in the United States was $42.4 million and $131.4 million, respectively (three months and year ended December 31, 2013 - $50.0 million and $97.6 million, respectively).

26. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation had the following commitments as at December 31, 2014:

Operating:

	2015	2016	2017	2018	2019	Thereafter
Office lease rentals	$ 15,868	$ 16,261	$ 34,036	$ 32,156	$ 32,199	$ 296,120
Diluent purchases	105,825	17,833	17,784	17,784	17,784	68,213
Transportation and storage	123,270	153,686	245,651	215,270	209,855	2,848,738
Other commitments	15,992	12,230	12,664	11,510	9,247	67,170
Commitments	**$ 260,955**	**$ 200,010**	**$ 310,135**	**$ 276,720**	**$ 269,085**	**$ 3,280,241**

Capital:

As part of normal operations, the Corporation has entered into a total of $25.4 million of capital commitments to be made in periods through 2016.

(b) Contingencies

The Corporation is involved in various legal claims associated with the normal course of operations. The Corporation believes that any liabilities that may arise pertaining to such matters would not have a material impact on its financial position.