YEAR AFTER YEAR

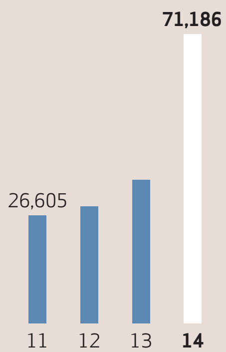
MEG Energy

2014 ANNUAL REPORT

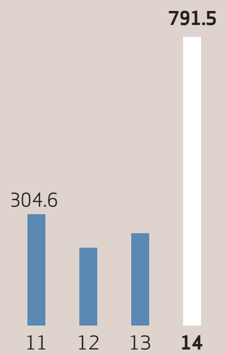
MEG Energy Corp. is a Canadian energy company focused on sustainable in situ development and production in the southern Athabasca oil sands region of Alberta.

Operational and Financial Highlights

Production
(barrels per day)



Cash flow
($millions)

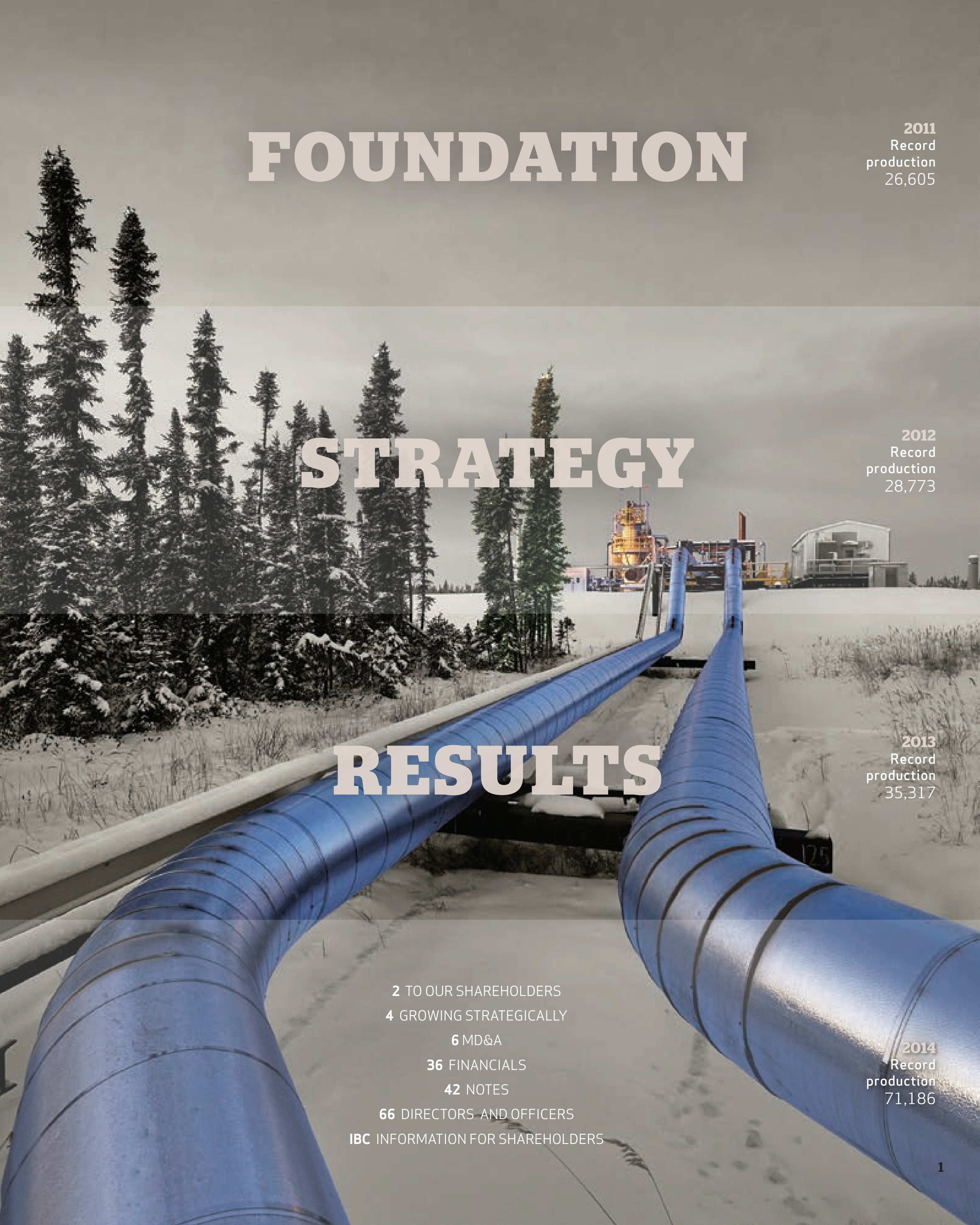


(Cdn$ millions, except as indicated)	**2014**	**2013**	**2012**
Bitumen production *(barrels per day)*	**71,186**	35,317	28,773
Bitumen sales *(barrels per day)*	**67,243**	33,715	28,845
Steam to oil ratio (SOR)	**2.5**	2.6	2.4
West Texas Intermediate (WTI) *(US$/barrel)*	**93.00**	97.96	94.21
West Texas Intermediate (WTI) *(Cdn$/barrel)*	**102.74**	100.86	94.14
Differential – WTI/blend *(%)*	**26.0%**	32.7%	31.2%
Bitumen realization *(Cdn$ per barrel)*	**62.67**	49.28	46.93
Net operating costs *(Cdn$ per barrel)*	**12.06**	10.01	9.98
Non-energy operating costs *(Cdn$ per barrel)*	**8.02**	9.00	9.71
Cash operating netback[1] *(Cdn$ per barrel)*	**44.87**	35.87	34.18
Cash flow from operations[2]	**791.5**	253.4	212.5
Per share, diluted[3]	**3.52**	1.13	1.06
Operating earnings[2]	**247.4**	0.4	21.2
Per share, diluted[2]	**1.10**	–	0.11
Revenue	**2,830.0**	1,334.5	1,050.5
Net earnings (loss)[3]	**(105.5)**	(166.4)	52.6
Per share, diluted	**(0.47)**	(0.75)	0.26
Total cash capital investment	**1,237.5**	2,111.8	1,567.9
Cash, cash equivalents and short-term investments	**656.1**	1,179.1	2,007.8
Long-term debt	**4,365.5**	4,004.6	2,488.6

1 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.

2 Cash flow from operations, Operating earnings, 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. Please see the "ADVISORY" section of this report.

3 Includes unrealized foreign exchange gains/losses on translation of the U.S. dollar denominated debt.



FOUNDATION

2011
Record
production
26,605

STRATEGY

2012
Record
production
28,773

RESULTS

2013
Record
production
35,317

2014
Record
production
71,186

To Our Shareholders

FROM MEG'S EARLIEST DAYS, WE HAVE ENDEAVOURED, YEAR AFTER YEAR, TO BUILD A BUSINESS MODEL AND CULTURE FOCUSED ON LEARNING, FLEXIBILITY AND THE POWER OF INNOVATION.

We've seen these key components of our strategy at play in our RISER initiative on Christina Lake Phases 1 and 2, and we are now focused on similar initiatives for Phase 2B. Our RISER 2B initiative will include the addition of brownfield developments at our central processing facilities, in combination with the continued implementation of our proprietary eMSAGP reservoir technologies. Collectively these initiatives target increased production at lower capital costs by harnessing technology and through the optimization of existing assets. We've also seen innovation in our research and development work with our HI-Q® technology and plans for a Diluent Removal Facility to support higher netbacks as a result of reduced diluent costs. And, we've seen it in our Hub and Spoke marketing strategy that aims to take greater control of the marketing of our products to get the best available price. Our ongoing efforts contributed to a strong year in 2014 and have set a solid foundation as we go forward.

While our business model has largely focused on moving quickly and efficiently to seize opportunities, it has also enabled us to respond to challenges, such as cyclical commodity prices. Our long term strategy remains focused on maximizing cash flows at all points in the cycle. At the time of writing this letter, we are in a lower portion of the cycle and oil prices have yet to show a sustained recovery from the rapid deterioration that began late in 2014.

In response to the volatile prices, we felt it was prudent to exercise flexibility within our 2015 capital budget by focusing on the basics and hence reduced capital spending plans to $305 million. The majority of this investment is directed to our relatively low sustaining and maintenance capital requirements, which will enable us to safely and reliably maintain production at current levels. And, building on a strong and steady fourth quarter, our production targets for 2015 position MEG for meaningful growth over 2014 average volumes.

Underlying our plans is a financial foundation that maintains significant liquidity. In addition to anticipated 2015 operating cash flow, MEG has maintained a strong cash position and has access to an undrawn five-year, US$2.5 billion dollar bank facility. Our bank facility, as well as all of our current outstanding debt, is free of financial maintenance covenants and our first long-term debt maturity is not due until 2020. In line with our overall business model, we have taken a long-term approach to our capital structure and we are well-positioned to work through commodity price cycles.

In this current price environment, we are also continuing to focus on refining our near to medium-term growth plans. A significant part of this focus will be to minimize capital requirements needed for our central processing facilities as we drive toward further production growth. This ongoing work will enable MEG to continue to grow production volumes at lower oil prices. At the same time, we will be maintaining our options to grow at higher rates in higher-priced environments, should it be prudent to do so. Our goal is to enhance our flexibility in order to be able to respond quickly to the right market signals at the right time.

As we look at our long-term vision, MEG currently has regulatory approvals to produce up to 210,000 barrels per day from our Christina Lake Regional Project, and the regulatory approval process for our 120,000 barrel per day Surmont Project is well-advanced. Collectively, these two project areas have 3 billion barrels of proved plus probable reserves with an additional 1.4 billion barrels of contingent resource. Looking further out, our Growth Properties contain an estimated 2.4 billion barrels of contingent resource that positions us well for added growth. Each of these projects are 100% owned by MEG, meaning that decisions around development and timing are within our control.

The successful start-up of Christina Lake Phase 2B, the ongoing implementation of MEG's RISER initiative and the steady and reliable performance from Phases 1 and 2 all combined to more than double our production in 2014 to a record 71,186 barrels per day. We are now targeting further

increases to between 78,000 and 82,000 barrels per day in 2015. Importantly, we have the flexibility to increase production rates under the right conditions and we have much of the required infrastructure already in place to do so. Our focus will remain on those projects that provide the best return at the lowest cost and that have the quickest path to cash flow growth.

Further supporting our operational and financial flexibility is our marketing strategy. In 2014, expansion of MEG's jointly owned Access Pipeline from our Christina Lake site to the Edmonton marketing hub was successfully completed. With Access Pipeline, we have the capacity to move our growing production to the Edmonton hub at a low cost, which protects significant cash flow for the corporation even in low price environments. In addition, our Stonefell terminal is playing a major role in mitigating short-term market disruptions and provides a key launch point for MEG to transport barrels by various means to the best markets.

Recent market connections include additional access to the U.S. Gulf Coast through the Enbridge Flanagan-Seaway pipeline system, on which we've begun shipping product, with increased secured capacity available in the future.

Other options that have been implemented include our direct connection from Stonefell to rail-loading facilities, which we have used to our advantage over the course of 2014, as well as proprietary barging options available on the U.S. Inland Waterway system. These spokes support a flexible strategy, as both rail and barge transportation options are designed to be ramped up or down relatively quickly as market conditions change.

With the combination of MEG's high quality resource base, the solid performance of our producing and marketing assets, and the expertise of our people, we are looking forward to 2015 and beyond as we continue to implement our long-term strategic plans.

I would like to thank the entire MEG team and your dedicated Board of Directors for their contributions, and our shareholders for your continued support.

Sincerely,

Bill McCaffrey
President and CEO

Record annual production of
71,186 barrels per day
102% over 2013 average annual rates

Non-energy operating costs at
$8.02 per barrel
11% lower than 2013 costs

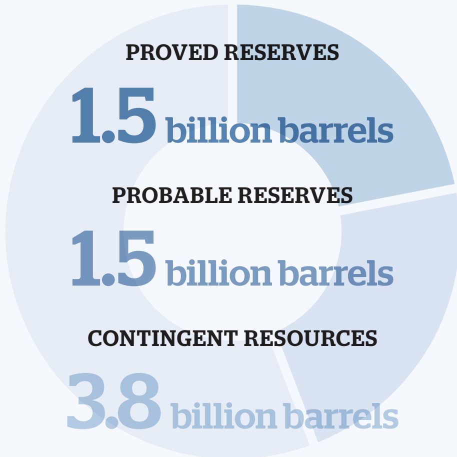
Cash flow from operations of
$792 million
212% over 2013 cash flow

GROWING STRATEGICALLY

From our established, high-quality resource base to our low-capital, technology-focused production initiatives and our innovative Hub and Spoke marketing strategy, MEG strives to find ways to maximize the value in every barrel that we produce across the full value chain.

RESOURCE BASE

MEG has secured more than 2,300 square kilometres (900 square miles) of oil sands leases in the southern Athabasca region of Alberta—an area that we know well. In addition to our current development focus at Christina Lake, MEG's exploration programs have defined high-quality resource opportunities at both our Surmont and Growth Property areas. With their similar geology and proximity to Christina Lake and our existing infrastructure, these areas will be central to MEG's longer-term development plans.



Estimates of MEG's reserves and contingent resources are based upon a report prepared by GLJ Petroleum Consultants Ltd., effective as of December 31, 2014. Contingent resources are best-estimate. There is no certainty that it will be commercially viable to produce any of the contingent resources. Statements relating to reserves and contingent resources estimates and certain other statements in this annual report including those relating to MEG's development plans and 2015 goals and expectations constitute forward-looking information. For further information and important advisories regarding forward-looking information and MEG's reserves and resources estimates, please refer to MEG's annual information form dated March 4, 2015.

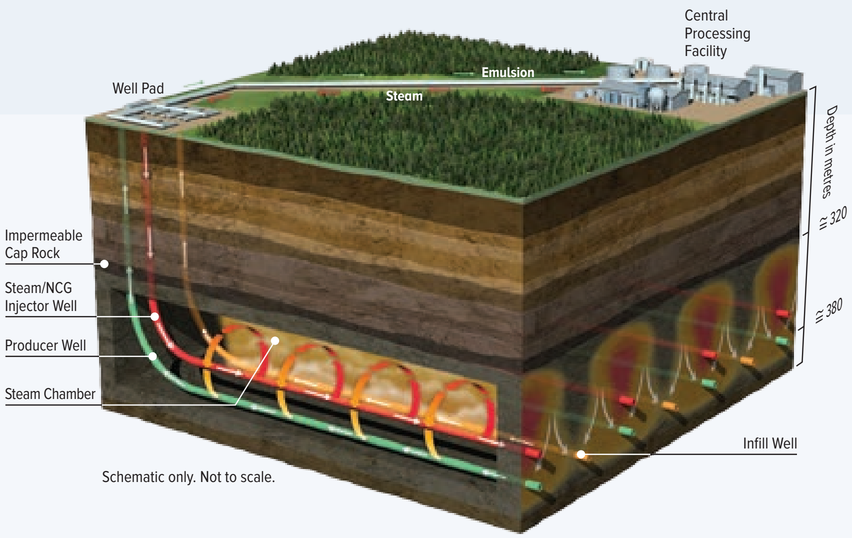
PRODUCTION TECHNOLOGY

RISER—the right way to grow

The RISER initiative has redefined how MEG approaches growth. Through RISER, existing assets are optimized by deploying proven technologies, debottlenecking existing plants and initiating brownfield expansions of our processing facilities before launching new greenfield phases. This approach to growth targets accelerated production and cash flow, increased recovery rates and reduced capital and operating costs per barrel, as well as a lower greenhouse gas intensity.

Proven Technologies

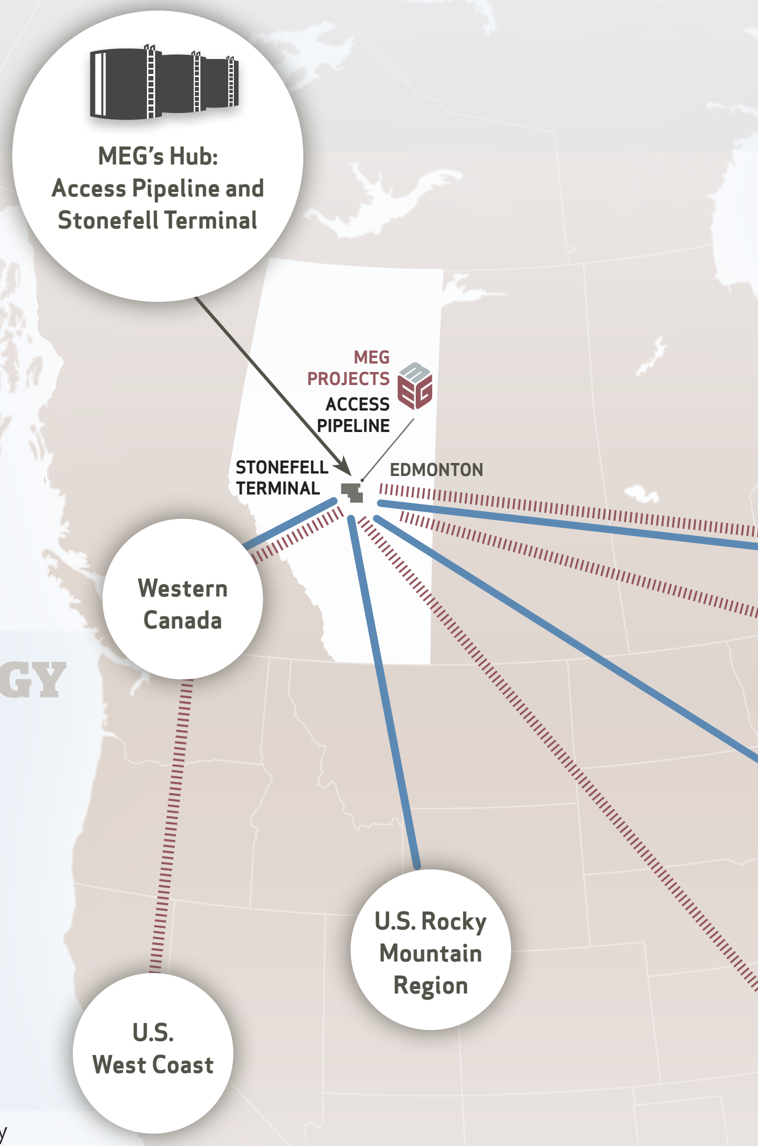
In the reservoir, RISER employs proven technologies: non-condensable gas injection and infill wells, in combination with proprietary reservoir development techniques in a process called enhanced modified steam and gas push (eMSAGP). With eMSAGP, steam is displaced with non-condensable gas to maintain reservoir pressure. The freed-up steam can then be redeployed to new wells. Infill wells are strategically placed between SAGD well pairs to capture incremental production from existing heat and developing gas pressure.



Schematic only. Not to scale.

Cogeneration

Cogeneration technology supports the reliability and efficiency of our operations while reducing net operating costs and significantly reducing total greenhouse gas emissions. In the cogeneration process, natural gas is used to simultaneously create steam and electricity at the project site. MEG uses both the steam and electricity produced for our operations and sells surplus power to the Alberta electrical grid. Surplus power generated from what would otherwise be waste-heat helps to offset MEG's energy costs and provides electricity to the power grid at a much lower than average greenhouse gas intensity.



HUB & SPOKE STRATEGY

MEG's Hub and Spoke marketing strategy connects our northern Alberta production base to current and emerging markets in North America and beyond.

The Hub

The strategy begins with the Access Pipeline. Access minimizes transportation costs and delivers our blend to the Edmonton hub—the launch point to current and developing markets. Access also provides a direct connection to our operations for the transport of diluent.

MEG's 900,000 barrel Stonefell storage facility is directly tied to Christina Lake through the Access Pipeline and offers many strategic marketing advantages. Stonefell provides the flexibility to absorb short-term market interruptions and capitalize when market conditions are more favourable. This benefit also applies to the purchase of diluent.

The Spokes

Long-term capacity on pipelines and flexible options for rail and barging on the U.S. Inland Waterway provide the spokes to reach high-value markets.

Rail

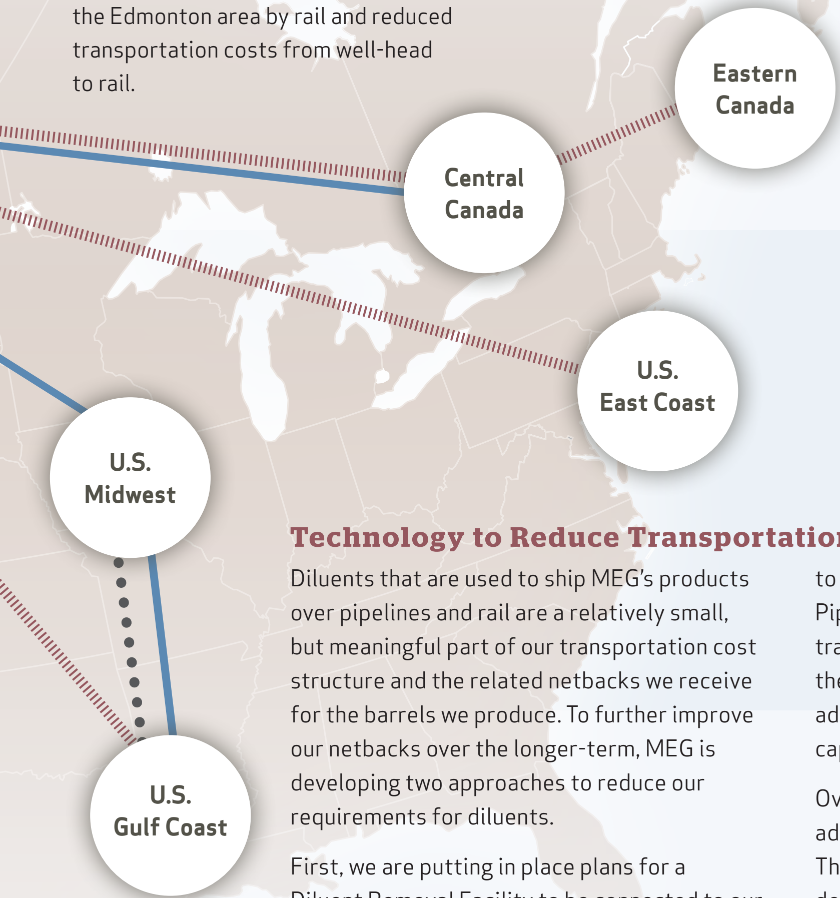
MEG's well-head to unit train loading capability via pipeline, with infrastructure connections across the continent, is a key spoke in MEG's Hub and Spoke strategy. This proprietary connection offers many distinct advantages for MEG: increased efficiencies for moving, loading and delivering our products by rail, better access to diluent supplies shipped to the Edmonton area by rail and reduced transportation costs from well-head to rail.

Barge

Barge transportation provides another spoke to move our product to the U.S. Gulf Coast. MEG has leased barges that are available for use as needed with volumes that can be ramped up or down in response to varying market conditions or pipeline supply disruptions.

Pipe

MEG has secured capacity on a number of existing and planned pipelines that can deliver our crude to various markets across North America and position us to reach further to global markets. Through our long-term commitment on the Flanagan-Seaway line that will grow over time with our growing production, we are able to access higher prices on the U.S. Gulf Coast. Moving our product by pipe continues to be the most efficient and reliable method of transportation, adding significant value to our overall marketing strategy.



Technology to Reduce Transportation Costs

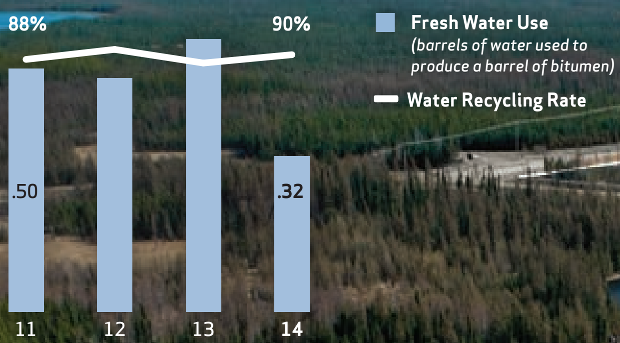
Diluents that are used to ship MEG's products over pipelines and rail are a relatively small, but meaningful part of our transportation cost structure and the related netbacks we receive for the barrels we produce. To further improve our netbacks over the longer-term, MEG is developing two approaches to reduce our requirements for diluents.

First, we are putting in place plans for a Diluent Removal Facility to be connected to our Stonefell Terminal. This technology will recycle diluents needed to move our heavy crude by pipeline to Stonefell and return the diluents to our Christina Lake project via the Access Pipeline. The resulting product, "railbit", can be transported by rail to refining markets across the continent. This technology is anticipated to add value by both increasing our rail shipping capacity and reducing operating costs.

Over the longer-term, MEG is continuing to advance its proprietary HI-Q® technology. The HI-Q® process has been successfully demonstrated to modify bitumen blends to a product suitable for shipping by pipeline without diluent.

GROWING RESPONSIBLY

Water Use Intensity



2014 verification in progress.

All of MEG's fresh water use is sourced from non-potable ground water that is not suitable for consumption or agricultural uses.

GHG Intensity

(g/MJ)

Source: Jacobs Consultancy, "Life Cycle Assessment of North America and Imported Crudes" July 2009.

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of the financial condition and performance of MEG Energy Corp. ("MEG" or the "Corporation") for the year ended December 31, 2014 is dated March 3, 2015. This MD&A should be read in conjunction with the Corporation's audited consolidated financial statements and notes thereto for the year ended December 31, 2014 and its Annual Information Form for the year ended December 31, 2014. All tabular amounts are stated in thousands of Canadian dollars ($ or C$) unless indicated otherwise.

Overview

MEG is an oil sands company focused on sustainable in situ oil sands development and production in the southern Athabasca oil sands region of Alberta, Canada. MEG is actively developing enhanced oil recovery projects that utilize steam-assisted gravity drainage ("SAGD") extraction methods. MEG is not engaged in oil sands mining.

MEG owns a 100% working interest in over 900 square miles of oil sands leases. In a report dated effective December 31, 2014 ("GLJ Report"), with a preparation date of January 30, 2015, GLJ Petroleum Consultants Ltd. estimated that the oil sands leases it had evaluated contained 3.0 billion barrels of proved plus probable bitumen reserves and 3.8 billion barrels of contingent bitumen resources (best estimate).

The Corporation has identified two commercial SAGD projects; the Christina Lake Project and the Surmont Project. The Christina Lake Project has received regulatory approval for 210,000 barrels per day ("bbls/d") of production and MEG has applied for regulatory approval for 120,000 bbls/d of production at the Surmont Project. The ultimate production rate and life of each project will be dependent on a number of factors, including the size of each phase, the performance of each phase and the development schedule. In addition, the Corporation holds other leases (the "Growth Properties") that are still in the resource definition stage and that are anticipated to provide significant additional development opportunities.

MEG is currently focused on the phased development of the Christina Lake Project. MEG's first two production phases at the Christina Lake Project, Phases 1 and 2, commenced production in 2008 and 2009, respectively, with a combined design capacity of 25,000 bbls/d. Phase 2B, an expansion with a design capacity of 35,000 bbls/d, commenced production in the fourth quarter of 2013 and attained its full design capacity during the second quarter of 2014. In 2012, the Corporation announced the RISER initiative for Phases 1 and 2, which was designed to achieve increased production from existing Phase 1 and 2 assets, with relatively low capital and operating costs. The RISER initiative uses a combination of proprietary reservoir technologies, redeployment of steam, and facilities modifications including plant debottlenecking and expansions. 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 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.

MEG's next phase of production growth will be primarily driven by the application of RISER on Phase 2B. RISER 2B includes the application of a combination of proprietary reservoir technologies, redeployment of steam and a major brownfield expansion of the existing Phase 2B facilities. Utilizing the results of recent production testing of the Phase 2B facility, MEG is in the process of designing a series of brownfield expansions of Phase 2B. Given the economic attractiveness of this strategy, MEG has prioritized RISER 2B ahead of its next greenfield expansion at Christina Lake.

The Surmont Project, which is situated along the same geological trend as Christina Lake, has an anticipated design capacity of approximately 120,000 bbls/d over multiple phases. MEG filed a regulatory application for the project in September 2012. The proposed project is expected to benefit from the use of a standardized plant design which will include the use of SAGD technology and include multi-well production pads, electricity and steam cogeneration and other facilities similar to MEG's current Christina Lake Project. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake operations. This area has been extensively explored and developed for natural gas projects, and more recently for oil sands resources. Other thermal recovery projects are already operating in this area.

MEG also holds a 50% interest in the Access Pipeline, a strategic dual pipeline system that connects the Christina Lake Project to a large regional upgrading, refining, diluent supply and transportation hub in the Edmonton, Alberta area. In the third quarter of 2014, MEG completed an expansion of the Access Pipeline, which included the construction of a 42-inch blend line from Christina Lake to the Edmonton, Alberta area. The expansion of the Access Pipeline will accommodate anticipated increases in production from

Christina Lake as well as provide expansion capacity for future production volumes from the Surmont Project and from MEG's Growth Properties. MEG's 50% interest of the initial capacity in the expanded 42-inch line is approximately 200,000 bbls/d of blended bitumen. The previous 24-inch blend line is planned to be reversed and converted to diluent service in 2015.

In addition to the Access Pipeline, MEG owns 100% of the Stonefell Terminal, located near Edmonton, Alberta. The Stonefell Terminal was commissioned in the fourth quarter of 2013 and has 900,000 barrels of strategic terminalling and storage capacity. The Stonefell Terminal is strategically located near the southern end of the Access Pipeline and is connected to local and export markets by pipeline, in addition to being pipeline connected to a third party rail-loading terminal at Bruderheim, Alberta. This combination of pipeline and rail facilities allows for both the loading of bitumen blend for transport and the receipt of diluent, thereby giving access to multiple blend markets and diluent sources throughout North America.

Summary Annual Information

($000s, except per share amounts)	**2014**	**2013**	**2012**
Revenue[1]	**2,829,964**	1,334,497	1,050,504
Net earnings (loss)	**(105,538)**	(166,405)	52,569
Per share – basic	**(0.47)**	(0.75)	0.27
Per share – diluted	**(0.47)**	(0.75)	0.26
Total assets	**9,930,108**	9,447,741	8,018,679
Total non-current liabilities	**4,700,771**	4,209,719	2,667,860

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

Revenue has increased primarily as a result of the increase in production from the Christina Lake Project. The increase in production is due to the implementation of RISER on Christina Lake Phases 1 and 2 and the start-up of Christina Lake Phase 2B. The expanded steam generation capacity and improved reservoir efficiency from the RISER implementation enabled the Corporation to place additional wells into production in 2013. Steam injection into the Phase 2B well pairs commenced in the third quarter of 2013 and the Corporation achieved first production from Phase 2B in the fourth quarter of 2013.

Net earnings (loss) has been impacted by unrealized foreign exchange gains and losses (2014 – $333.1 million loss; 2013 – $177.4 million loss; 2012 – $35.8 million gain) on translation of the Corporation's U.S. dollar-denominated debt and U.S. dollar cash and cash equivalents. Net earnings (loss) has also been impacted by the increase in depletion and depreciation expense (2014 – $378.5 million; 2013 – $189.1 million; 2012 – $145.0 million), the increase in general and administrative expense (2014 – $111.4 million; 2013 – $92.8 million; 2012 – $70.6 million), the increase in interest expense (2014 – $189.2 million; 2013 – $110.3 million; 2012 – $91.8 million) and the recording of other expenses relating to an inventory write-down and contract cancellation costs (2014 – $36.1 million; 2013 and 2012 – nil).

Total assets have increased due to capital investment in the Christina Lake Project, the RISER initiative, the Access Pipeline and the Stonefell Terminal, as well as resource definition at the Surmont Project and the Growth Properties.

Investment activity was partially funded by:

- the issuance of US$800 million in aggregate principal amount of 6.375% senior unsecured notes in July 2012;
- the issuance of 24.2 million common shares at a price of $33.00 per share for proceeds of $774.8 million, net of issue costs, in December 2012;
- the increased borrowing under the senior secured term loan of US$300.0 million in February 2013;
- the issuance of US$1.0 billion in aggregate principal amount of 7.0% senior unsecured notes in the fourth quarter of 2013; and
- cash flow from operations of $791.5 million for 2014 (2013 – $253.4 million; 2012 – $212.5 million).

For a detailed discussion of the Corporation's investing activities, see "LIQUIDITY AND CAPITAL RESOURCES – Cash Flows – Investing Activities".

Operational and Financial Highlights

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

($000s, except as indicated)	**2014**	**2013**
Bitumen production *(bbls/d)*	**71,186**	35,317
Bitumen sales *(bbls/d)*	**67,243**	33,715
Bitumen realization *($/bbl)*	**62.67**	49.28
Net operating costs *($/bbl)*[1]	**12.06**	10.01
Non-energy operating costs *($/bbl)*	**8.02**	9.00
Cash operating netback[2] *($/bbl)*	**44.87**	35.87
Cash flow from operations[3]	**791,458**	253,424
Per share, diluted[3]	**3.52**	1.13
Operating earnings[3]	**247,353**	386
Per share, diluted[3]	**1.10**	-
Revenue[4]	**2,829,964**	1,334,497
Net earnings (loss)[5]	**(105,538)**	(166,405)
Per share, basic	**(0.47)**	(0.75)
Per share, diluted	**(0.47)**	(0.75)
Total cash capital investment[6]	**1,237,539**	2,111,824
Cash, cash equivalents and short-term investments	**656,097**	1,179,072
Long-term debt[7]	**4,365,502**	4,004,575
Bitumen Reserves and Contingent Resources *(millions of barrels, before royalties)*		
Bitumen Reserves *(millions of barrels, before royalties)*[8]		
Proved (1P) Reserves	**1,501**	1,446
Probable Reserves	**1,505**	1,451
Proved Plus Probable Reserves (2P) Reserves	**3,006**	2,897
Bitumen Contingent Resources *(millions of barrels, before royalties)*[8]		
Best Estimate Contingent Resources (2C)[9]	**3,793**	3,653

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 measures are reconciled to net earnings (loss) and net cash provided by (used in) operating activities in accordance with IFRS under the heading "NON-GAAP MEASURES" 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 $368.5 million for the year ended December 31, 2014 and $213.7 million for the 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.

8 See Oil and Gas Information in the "ADVISORY" section for definitions of proved, probable and best estimate contingent resources. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

9 These volumes are the arithmetic sums of the best estimate contingent resources for Christina Lake, Surmont and the Growth Properties.

Bitumen Production

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 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 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 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 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.

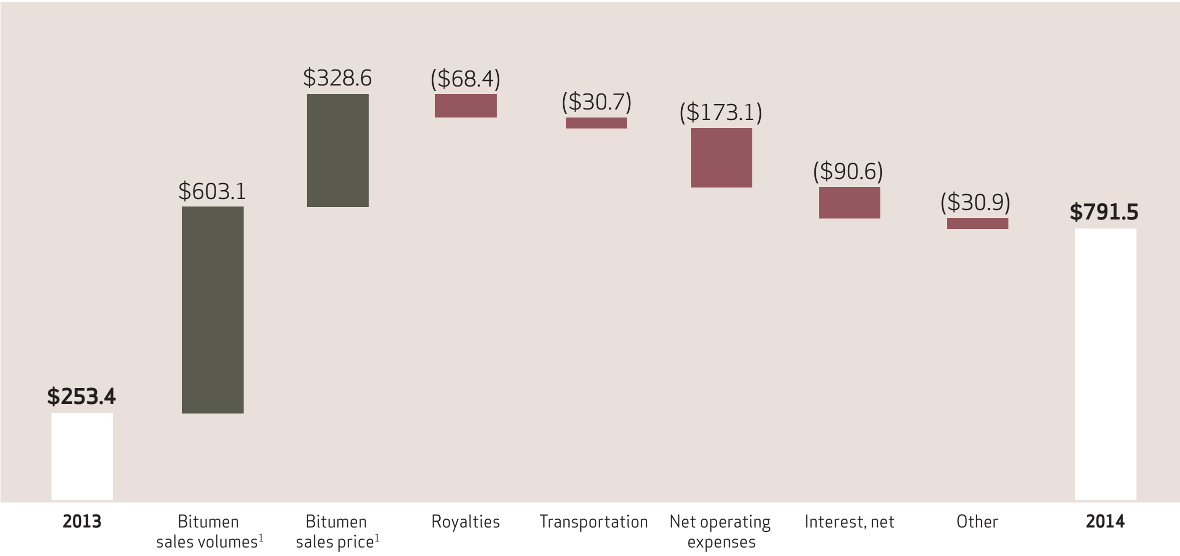
- Energy operating costs increased to $6.30 per barrel for the year ended December 31, 2014 compared to $4.62 per barrel for the same period in 2013. Energy costs increased as a result of the increase in natural gas prices, which increased to an average of $4.62 per mcf for the year ended December 31,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

($millions)



1 Net of diluent

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

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 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 $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

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.

Outlook

Annual non-energy operating costs for 2015 are targeted to be in the range of $8 to $10 per barrel and annual bitumen production volumes are targeted to be in the 78,000 to 82,000 bbls/d range, while providing for two scheduled plant turnarounds. The Corporation's 2015 planned capital program totals $305 million.

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 MD&A 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 $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 $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

	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 steam to oil ratio ("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

($000)	2014	2013
Petroleum sales – proprietary[1]	**$ 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 MEASURES" section of this MD&A.

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

($bbl)

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

($/bbl)	2014	2013
Bitumen realization[1]	**$ 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, 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.

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

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 $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 more than 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.

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 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

($000)	**2014**	2013
Petroleum sales – third party	**$ 149,260**	$ 101,750
Purchased product and storage	**(163,387)**	(104,115)
Net marketing activity[1]	**$ (14,127)**	$ (2,365)

1 Net marketing activity is a non-GAAP measure as defined in the "NON-GAAP MEASURES" 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

($000)	**2014**	2013
Depletion and depreciation	**$ 378,544**	$ 189,147
Depletion and depreciation per barrel	**$ 15.42**	$ 15.37

Depletion and depreciation expense for the year ended December 31, 2014 totalled $378.5 million compared to $189.1 million in 2013. The increases are primarily due to a 99% increase in bitumen sales volumes for the year ended December 31, 2014, compared to the same periods in 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

($000)	2014	2013
General and administrative costs	$ 145,949	$ 123,194
Capitalized general and administrative costs	(34,583)	(30,366)
General and administrative expense	$ 111,366	$ 92,828
General and administrative expense per barrel of production	$ 4.29	$ 7.20

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

($000)	2014	2013
Stock-based compensation costs	$ 62,484	$ 50,059
Capitalized stock-based compensation costs	(14,174)	(11,267)
Stock-based compensation expense	$ 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 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 $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

($000)	2014	2013
Research and development	$ 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 $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)

($000)	2014	2013
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (368,450)**	$ (213,715)
US$ denominated cash and cash equivalents	**35,301**	36,353
Unrealized loss on foreign exchange	**(333,149)**	(177,362)
Realized loss on foreign exchange	**(5,480)**	(2,916)
Net foreign exchange loss	**$ (338,629)**	$ (180,278)
US$/C$ exchange rates:		
Beginning of period	**1.0636**	0.9949
End of period	**1.1601**	1.0636

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

($000)	2014	2013
Total interest expense	**$ 265,140**	$ 186,835
Less capitalized interest	**(75,975)**	(76,529)
Net interest expense	**189,165**	110,306
Accretion on decommissioning provision	**4,535**	4,763
Unrealized fair value gain on embedded derivative financial liabilities	**(2,652)**	(14,352)
Unrealized fair value loss (gain) on interest rate swaps	**1,183**	(4,904)
Realized loss on interest rate swaps	**5,056**	4,720
Unrealized fair value gain on other assets	**(429)**	–
Net finance expense	**$ 196,858**	$ 100,533
Average effective interest rate[1]	**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 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 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 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 $5.1 million for the year ended December 31, 2014, on the interest rate swap contracts, compared to a loss of $4.7 million for the year ended December 31, 2013. In addition, the Corporation recognized an unrealized loss of $1.2 million for the year ended December 31, 2014. This compared to an unrealized gain of $4.9 million for year ended December 31, 2013.

Other Expenses

($000)		2014		2013
Inventory write-down	**$**	**19,668**	$	–
Contract cancellation costs		**16,455**		–
Other expenses	**$**	**36,123**	$	–

The Corporation recognized other expenses of $36.1 million for the year ended December 31, 2014 (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

($000)		2014		2013
Deferred income tax expense	**$**	**85,776**	$	22,347

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 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 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 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.

Summary Of Quarterly Results

The following table summarizes selected financial information for the Corporation for the preceding eight quarters:

	2014				2013			
($ millions, except per share amounts)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue[1]	**$ 614.8**	**$ 706.4**	**$ 829.2**	**$ 679.6**	$ 350.3	$ 401.8	$ 324.4	$ 258.0
Net earnings (loss)	**(150.1)**	**(101.0)**	**249.0**	**(103.4)**	(148.2)	115.4	(62.3)	(71.3)
Per share – basic	**(0.67)**	**(0.45)**	**1.12**	**(0.46)**	(0.67)	0.52	(0.28)	(0.32)
Per share – diluted	**(0.67)**	**(0.45)**	**1.11**	**(0.46)**	(0.67)	0.51	(0.28)	(0.32)

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

Revenue for the eight most recent quarters has been impacted by the increases in production and fluctuations in blend sales pricing. Revenue for the second quarter of 2014 and 2013 had reduced production volumes as a result of scheduled annual maintenance activities at the Christina Lake facilities.

Net earnings (loss) during the periods noted was impacted by:

- increased blend sales volumes due to the start-up of Christina Lake Phase 2B in the fourth quarter of 2013 and implementation of RISER on Phases 1 and 2, which has allowed additional wells to be placed into production;
- fluctuations in natural gas and power pricing;
- fluctuations in blend sales pricing due to changes in the price of WTI and the differential between WTI and the Corporation's AWB;
- changes in the value of the Canadian dollar relative to the U.S. dollar as blend sales prices are determined by reference to U.S. benchmarks;
- foreign exchange gains and losses attributable to fluctuations in the rate of exchange between the Canadian and U.S. dollar in translating the Corporation's U.S. dollar denominated debt (net of U.S. dollar denominated cash, cash equivalents and short-term investments);
- an increase in depletion and depreciation expense as a result of the increase in bitumen sales volumes and higher estimated future development costs;
- higher general and administrative expense as a result of the planned increase in office staff to support growth;
- an increase in interest expense as a result of the increase in long-term debt;
- an increase in interest expense due to the weakening Canadian dollar and its impact on U.S. dollar denominated interest expense;
- scheduled annual plant maintenance activities performed in the second quarters of 2013 and 2014;
- use of production for blend linefill for the Access Pipeline expansion in the third quarter of 2014;
- utilizing production for the start-up of the Flanagan South Pipeline in the fourth quarter of 2014; and
- recording expenses in the fourth quarter of 2014 relating to a decrease in the value of bitumen blend inventory and non-recurring field asset construction contract cancellation costs as a result of the reduction of the Corporation's capital program for 2015.

Capital Investing

($000)	**2014**	2013
Intraphase growth	**$ 341,088**	$ 500,472
Portfolio growth		
Christina Lake	**183,396**	196,359
Resource development	**83,444**	227,581
Growth infrastructure	**84,270**	412,738
Enhancements and other	**74,905**	43,757
Total portfolio growth	**426,015**	880,435
Marketing initiatives		
Access Pipeline	**194,867**	257,629
Other	**74,127**	161,582
Total marketing initiatives	**268,994**	419,211
Sustaining and maintenance	**145,272**	100,309
Other	**56,170**	211,397
Total cash capital investment	**1,237,539**	2,111,824
Capitalized interest	**75,975**	76,529
	1,313,514	2,188,353
Non-cash	**67,738**	39,799
Total capital investment	**$ 1,381,252**	$ 2,228,152

MEG's 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 $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 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.

Liquidity and Capital Resources

($000)	**2014**	2013
Cash and cash equivalents	**$ 656,097**	$ 1,179,072
Senior secured term loan (December 31, 2014 – US$1.262 billion; December 31, 2013 – US$1.275 billion; due 2020)	**1,463,466**	1,355,558
US$2.5 billion revolver (December 31, 2013 – US$2.0 billion; due 2019)	**–**	–
6.5% senior unsecured notes (US$750.0 million; due 2021)	**870,075**	797,700
6.375% senior unsecured notes (US$800.0 million; due 2023)	**928,080**	850,880
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,160,100**	1,063,600
Total debt[1]	**$ 4,421,721**	$ 4,067,738

1 Total debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The Corporation uses this non-GAAP measure to analyze leverage and liquidity. Total debt less the current portion of the senior secured term loan, unamortized financial derivative liability discount and unamortized deferred debt issue costs is equal to long-term debt as reported in the Corporation's consolidated financial statements as at December 31, 2014 and December 31, 2013.

Capital Resources

As at December 31, 2014, the Corporation's available capital resources included $656.1 million of cash and cash equivalents and an additional undrawn US$2.5 billion syndicated revolving credit facility and a US$500 million guaranteed letter of credit facility under which US$164.8 million of letters of credit have been issued.

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. The revolving credit facility remains undrawn as at December 31, 2014. The transaction was completed through an amendment of MEG's existing credit facility. The $8.6 million of debt-issue costs have been deferred and are being amortized over the term of the revolving credit facility. 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. 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 in November 2019. Letters of credit issued under the facility with EDC will not consume capacity of the revolving credit facility. Related issue costs of $1.5 million have been deferred and are being amortized over the term of the guaranteed credit facility.

Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Corporation to meet its current and future obligations, to make scheduled principal and interest payments, and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Corporation's cash flow and the development of projects are dependent on factors discussed in the "RISK FACTORS" section below.

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, beginning on March 31, 2014. The $13.0 million of debt-issue costs have been deferred and are being amortized over the term of the revolving credit facility.

On May 24, 2013, MEG expanded its senior secured revolving credit facility from US$1.0 billion to US$2.0 billion. In addition, the Corporation extended the maturity of the revolving credit facility by one year to May 24, 2018. The transaction was completed through an amendment of MEG's existing credit facility. The $8.7 million of debt-issue costs have been deferred and are being amortized over the term of the revolving credit facility.

On February 25, 2013, the Corporation re-priced, increased and extended its 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. The amended 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 being repaid in quarterly installments of US$3.25 million, with the balance due March 31, 2020. The $6.8 million of debt-issue costs have been deferred and are being amortized over the term of the revolving credit facility.

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. 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's cash is held in high interest savings accounts with a diversified group of highly-rated financial institutions. The Corporation has also invested in high grade, liquid, short-term instruments such as government, commercial and bank paper as well as term deposits. To date, the Corporation has experienced no material loss or lack of access to its cash in operating accounts, invested cash or cash equivalents. However, the Corporation can provide no assurance that access to its invested cash and cash equivalents will not be impacted by adverse conditions in the financial markets. While the Corporation monitors the cash balances in its operating and investment accounts according to its investment policy and adjusts the cash balances as appropriate, these cash balances could be impacted if the underlying financial institutions or corporations fail or are subject to other adverse conditions in the financial markets.

Cash Flows Summary

($000)	**2014**	2013
Net cash provided by (used in):		
Operating activities	**$ 767,500**	$ 125,768
Investing activities	**(1,312,440)**	(1,789,980)
Financing activities	**(13,336)**	1,332,088
Foreign exchange gains on cash and cash equivalents held in foreign currency	**35,301**	36,353
Change in cash and cash equivalents	**$ (522,975)**	$ (295,771)

Cash Flows – Operating Activities

Net cash provided by operating activities totalled $767.5 million for the year ended December 31, 2014 compared to $125.8 million for the year ended December 31, 2013. The increase in cash flows from operating activities is primarily due to increased blend sales revenues as a result of the increased production.

Cash Flows – Investing Activities

Net cash used in investing activities for the year ended December 31, 2014 primarily consisted of $1.3 billion in cash capital investment (refer to the "CAPITAL INVESTING" section of this MD&A for further details) and a $3.3 million decrease in non-cash investing working capital. Net cash used in investing activities for the year ended December 31, 2013 primarily consisted of $2.2 billion in cash capital investment and a $41.5 million purchase of diluent linefill. 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. These amounts were partially offset by a $430.3 million increase in non-cash investing working capital which is due mainly to the $533.0 million decrease in short-term investments.

Cash Flows – Financing Activities

Net cash used in financing activities for the year ended December 31, 2014 consisted of $14.5 million of debt principal repayment and $10.0 million in financing costs. These amounts were partially offset by $11.2 million received from the exercise of stock options.

Net cash provided by financing activities for the year ended December 31, 2013 primarily consisted of $1.3 billion of net proceeds from the US$1.0 billion issuance of senior unsecured notes and US$300 million increase in the senior secured term loan and $31.7 million of proceeds received from the exercise of stock options. These amounts were partially offset by $13.5 million of debt principal repayments and $8.7 million in financing costs.

Shares Outstanding

As at December 31, 2014, the Corporation had the following share capital instruments outstanding:

Common shares	223,846,891
Convertible securities	
Stock options outstanding – exercisable and unexercisable	7,865,788
RSUs and PSUs outstanding	2,745,439

As at February 19, 2015, the Corporation had 223,846,891 common shares, 7,809,017 stock options and 2,677,658 restricted share units and performance share units outstanding.

Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities may be retired earlier due to mandatory repayments.

($000)	**Total**	**Less than 1 year**	**1 – 3 years**	**4 – 5 years**	**More than 5 years**
Long-term debt[1]	$ 4,421,721	$ 15,081	$ 30,162	$ 30,162	$ 4,346,316
Interest on long-term debt[1]	1,862,853	251,735	501,922	499,511	609,685
Decommissioning obligation[2]	707,760	1,835	9,895	11,400	684,630
Transportation and storage[3]	3,796,470	123,270	399,337	425,125	2,848,738
Contracts and purchase orders[4]	420,433	163,319	65,406	56,325	135,383
Operating leases[5]	426,640	15,868	50,297	64,355	296,120
	$11,635,877	**$ 571,108**	**$ 1,057,019**	**$ 1,086,878**	**$ 8,920,872**

1 This represents the scheduled principal repayment of the senior secured credit facility and the senior unsecured notes and associated interest payments based on interest and foreign exchange rates in effect on December 31, 2014.

2 This represents the undiscounted future obligation associated with the decommissioning of the Corporation's crude oil and transportation and storage assets.

3 This represents transportation and storage commitments from 2015 to 2037.

4 This represents the future commitment associated with the Corporation's capital program, diluent purchases and other operating and maintenance commitments.

5 This represents the future commitments for the Calgary Corporate office.

Non-GAAP Measures

Certain financial measures in this MD&A 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 through various 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 17 in the notes to the 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.

($000)	**2014**	2013
Net cash provided by (used in) operating activities	**$ 767,500**	$ 125,768
Add:		
Net change in non-cash operating working capital items	**5,610**	123,461
Contract cancellation costs	**16,455**	–
Decommissioning expenditures	**1,893**	4,195
Cash flow from operations	**$ 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.

($000)	**2014**	2013
Net loss	**$ (105,538)**	$ (166,405)
Add (deduct):		
Unrealized loss on foreign exchange[1]	**333,149**	177,362
Unrealized gain on derivative financial liabilities[2]	**(1,469)**	(19,256)
Unrealized fair value gain on other assets[3]	**(429)**	–
Contract cancellation costs[4]	**16,455**	–
Deferred tax expense relating to these adjustments	**5,185**	8,685
Operating earnings	**$ 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 year-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 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.

Critical Accounting Policies and Estimates

The Corporation's critical accounting estimates are those estimates having a significant impact on the Corporation's financial position and operations and that require management to make judgments, assumptions and estimates in the application of IFRS. Judgments, assumptions and estimates are based on historical experience and other factors that management believes to be reasonable under current conditions. As events occur and additional information is obtained, these judgments, assumptions and estimates may be subject to change. The following are the critical accounting estimates used in the preparation of the Corporation's consolidated financial statements.

Property, Plant and Equipment

Items of property, plant and equipment, including oil sands property and equipment, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Capitalized costs associated with the Corporation's producing oil sands properties, including estimated future development costs, are depleted using the unit-of-production method based on estimated proved reserves. The Corporation's oil sands facilities are depreciated on a unit-of-production method based on the facilities' productive capacity over their estimated remaining useful lives. The costs associated with the Corporation's interest in transportation and storage assets are depreciated on a straight-line basis over the estimated remaining useful lives of the assets. The determination of future development costs, proved reserves, productive capacity and remaining useful lives are subject to significant judgments and estimates.

Exploration and Evaluation Assets

Pre-exploration costs incurred before the Corporation obtains the legal right to explore an area are expensed. Exploration and evaluation costs associated with the Corporation's oil sands activities are capitalized. These costs are accumulated in cost centres pending determination of technical feasibility and commercial viability at which point the costs are transferred to property, plant and equipment. If it is determined that an exploration and evaluation asset is not technically feasible or commercially viable and the Corporation decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to expense. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. The determination of proved or probable reserves is dependent on reserve evaluations which are subject to significant judgments and estimates.

Impairments

The carrying amounts of the Corporation's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the asset's recoverable amount is estimated. An impairment test is completed each year for intangible assets that are not yet available for use. Exploration and evaluation assets are assessed for impairment when they are reclassified to property, plant and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped into cash-generating units ("CGUs"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell. Exploration and evaluation assets are assessed for impairment within the aggregation of all CGUs in that segment.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value less costs to sell is defined as the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable, willing parties, less the costs of disposal.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized within net earnings during the period in which they arise. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro-rata basis.

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

Bitumen Reserves

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion and depreciation charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of oil sands property, plant and equipment carrying amounts.

Joint Operations

Judgment is required to determine whether an interest the Corporation holds in a joint arrangement should be classified as a joint operation or joint venture. The determination includes an assessment as to whether the Corporation has the rights to the assets and obligations for the liabilities of the arrangement or the rights to the net assets. The Corporation holds an undivided interest in Access Pipeline. As a result, the Corporation presents its proportionate share of the assets, liabilities, revenues and expenses of Access Pipeline on a line-by-line basis in the consolidated financial statements.

Decommissioning Provision

The Corporation recognizes an asset and a liability for any existing decommissioning obligations associated with the retirement of property, plant and equipment and exploration and evaluation assets. The provision is determined by estimating the fair value of the decommissioning obligation at the end of the period. This fair value is determined by estimating expected timing and cash flows that will be required for future dismantlement and site restoration, and then calculating the present value of these future payments using a credit-adjusted risk-free rate specific to the liability. Any change in timing or amount of the cash flows subsequent to initial recognition results in a change in the asset and liability, which then impacts the depletion and depreciation on the asset and accretion charged on the liability. Estimating the timing and amount of third party cash flows to settle these obligations is inherently difficult and is based on third party estimates and management's experience.

Deferred Income Taxes

The Corporation follows the liability method of accounting for income taxes. Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. The periods in which timing differences reverse are impacted by future earnings and capital expenditures. Rates are also affected by changes to tax legislation. Income taxes are recognized in net earnings except to the extent that they relate to items recognized directly in shareholders' equity, in which case the income taxes are recognized in shareholders' equity. The Corporation also makes interpretations and judgments on the application of tax laws for which the eventual tax determination may be uncertain. To the extent that interpretations change, there may be a significant impact on the consolidated financial statements.

Stock-based Compensation

Amounts recorded for stock-based compensation expense are based on several assumptions including the risk-free interest rate, the forfeiture rate, the expected volatility of the Corporation's share price and those of similar publicly listed enterprises, which may not be indicative of future volatility. Accordingly, those amounts are subject to measurement uncertainty.

Derivative Financial Instruments

The Corporation may utilize derivative financial instruments to manage its currency and interest rate exposures. These financial instruments are not used for trading or speculative purposes. The fair values of derivative financial instruments are estimated at the end of each reporting period based on expectations of future cash flows associated with the derivative instrument. Estimates of future cash flows are based on forecast interest and foreign exchange rates expected to be in effect over the remaining life of the contract. Any subsequent changes in these rates will impact the amounts ultimately recognized in relation to the derivative instruments.

Transactions with Related Parties

The only related party transactions during the year ended December 31, 2014, was the compensation of key management personnel. The Corporation considers directors and executive officers of the Corporation as key management personnel.

($000)	2014	2013
Salaries and short-term employee benefits	**$ 9,975**	$ 9,230
Share-based compensation expense	**13,539**	12,477
	$ 23,514	$ 21,707

During the year ended December 31, 2013, the Corporation paid $0.3 million in costs on behalf of WP Lexington Private Equity B.V. ("WP Lex"). WP Lex is considered to be a related party of the Corporation as two managing directors of WP Lex also hold positions as members of the Board of Directors of the Corporation.

Off-Balance Sheet Arrangements

At December 31, 2014 and December 31, 2013 the Corporation did not have any off balance sheet arrangements. The Corporation has certain operating or rental lease agreements, as disclosed in the Contractual Obligations and Commitments section of this MD&A, which are entered into in the normal course of operations. Payments of these leases are included as an expense as incurred over the lease term. No asset or liability value had been assigned to these leases as at December 31, 2014 and December 31, 2013.

New Accounting Policies

The Corporation has adopted the following revised standards effective January 1, 2014. These changes, along with all the corresponding 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 a 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.

Risk Factors

The Corporation's primary focus is on the ongoing development and operation of its oil sands assets. In developing and operating these assets, the Corporation is and will be subject to many risks, including the risks which have been categorized below as construction risks, operations risks and project development risks. Further information regarding the risk factors which may affect the Corporation is contained in the Annual Information Form ("AIF"), which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

Risks Arising From Construction Activities

Cost and Schedule Risk

Additional phases of development of the Christina Lake Project and the development of the Corporation's other projects may suffer from delays, cancellation, interruptions or increased costs due to many factors, some of which may be beyond the Corporation's control, including:

- engineering, construction and/or procurement performance falling below expected levels of output or efficiency;
- denial or delays in receipt of regulatory approvals, additional requirements imposed by changes in laws or non-compliance with conditions imposed by regulatory approvals;
- labour disputes or disruptions, declines in labour productivity or the unavailability of skilled labour;
- increases in the cost of labour and materials; and
- changes in project scope or errors in design.

If any of the above events occur, they could have a material adverse effect on the Corporation's ability to continue to develop the Christina Lake Project, the Corporation's facilities or the Corporation's other future projects and facilities, which would materially adversely affect its business, financial condition and results of operations.

Risks Arising From Operations

Operating Risk

The operation of the Corporation's oil sands properties and projects are and will continue to be subject to the customary hazards associated with recovering, transporting and processing hydrocarbons, such as fires, severe weather, natural disasters (including wildfires), explosions, gaseous leaks, migration of harmful substances, blowouts and spills. A casualty occurrence might result in the loss of equipment or life, as well as injury, property damage or the interruption of the Corporation's operations. The Corporation's insurance may not be sufficient to cover all potential casualties, damages, losses or disruptions. Losses and liabilities arising from uninsured or under-insured events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Operating Results

The Corporation's operating results are affected by many factors. The principal factors, amongst others, which could affect MEG's operating results include:

- a substantial decline in oil, bitumen or electricity prices, due to a lack of infrastructure or otherwise;
- lower than expected reservoir performance, including, but not limited to, lower oil production rates and/or higher steam-to-oil ratios;
- a lack of access to, or an increase in, the cost of diluent;
- an increase in the cost of natural gas;
- the reliability and maintenance of the Access Pipeline, Stonefell Terminal and MEG's other facilities;
- the need to repair existing horizontal wells, or the need to drill additional horizontal wells;
- the ability and cost to transport bitumen, diluent and bitumen diluent blends, and the cost to dispose of certain by-products;
- increased royalty payments resulting from changes in the regulatory regime;
- a lack of sufficient pipeline or electrical transmission capacity, and the effect that an apportionment may have on MEG's access to such capacity;
- the cost of labour, materials, services and chemicals used in MEG's operations; and
- the cost of compliance with existing and new regulations.

Labour Risk

The Corporation depends on its management team and other key personnel to run its business and manage the operation of its projects. The loss of any of these individuals could adversely affect the Corporation's operations. Due to the specialized nature of the Corporation's business, the Corporation believes that its future success will also depend upon its ability to continue to attract, retain and motivate highly skilled management, technical, operations and marketing personnel.

Project Development Risks

Reliance on Third Parties

The Christina Lake Project and the Corporation's future projects will depend on the successful operation and the adequate capacities of certain infrastructure owned and operated by third parties or joint ventures with third parties, including:

- pipelines for the transport of natural gas, diluent and blended bitumen;
- power transmission grids supplying and exporting electricity; and
- other third-party transportation infrastructure such as roads, rail, terminals, barges and airstrips.

The failure or lack of any or all of the infrastructure described above will negatively impact the operation of the Christina Lake Project and MEG's future projects, which in turn, may have a material adverse effect on MEG's business, results of operations and financial condition.

Reserves and Resources

There are numerous uncertainties inherent in estimating quantities of in-place bitumen reserves and resources, including many factors beyond the Corporation's control. In general, estimates of economically recoverable bitumen reserves and resources and the future net cash flow therefrom are based upon a number of factors and assumptions made as of the date on which the reserve and resource estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the effects of regulation by governmental agencies, and estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, the classification of such reserves and resources based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Although third parties have prepared the GLJ Report and other reviews, reports and projections relating to the viability and expected performance of the Christina Lake Project, the Surmont Project and the Growth Properties, the GLJ Report, the reviews, reports and projections and the assumptions on which they are based may not, over time, prove to be accurate. Actual production and cash flow derived from the Corporation's oil sands leases may vary from the GLJ Report and other reviews, reports and projections.

Financing Risk

Significant amounts of capital will be required to develop future phases of the Christina Lake Project, the Surmont Project and the Growth Properties. At present, cash flow from the Corporation's operations is largely dependent on the performance of a single project and a major source of funds available to the Corporation is the issuance of additional equity or debt. Capital requirements are subject to capital market risks, including the availability and cost of capital. There can be no assurance that sufficient capital will be available or be available on acceptable terms or on a timely basis, to fund the Corporation's capital obligations in respect of the development of its projects or any other capital obligations it may have. The Corporation may not generate sufficient cash flow from operations and may not have additional equity or debt available to it in amounts sufficient to enable it to make payments with respect to its indebtedness or to fund its other liquidity needs. In these circumstances, the Corporation may need to refinance all or a portion of its indebtedness on or before maturity. The Corporation may not be able to refinance any of its indebtedness on commercially reasonable terms or at all.

Commodity Price Risk

The Corporation's business, financial condition, results of operations and cash flow are dependent upon the prevailing prices of its bitumen blend, condensate, power and natural gas. Prices of these commodities have historically been extremely volatile and fluctuate significantly in response to regional, national and global supply and demand, and other factors beyond the Corporation's control.

Declines in prices received for the Corporation's bitumen blend could materially adversely affect the Corporation's business, financial position, results of operations and cash flow. In addition, any prolonged period of low bitumen blend prices or high natural gas or condensate prices could result in a decision by the Corporation to suspend or reduce production. Any suspension or reduction of production would result in a corresponding decrease in the Corporation's revenues and could materially impact the Corporation's ability to meet its debt service obligations.

Interest Rate Risk

The Corporation has obtained certain credit facilities to finance a portion of the capital costs of the Christina Lake Project and to fund the Corporation's other development and acquisition activities. Variations in interest rates could result in significant changes to debt service requirements and would affect the financial results of the Corporation. If over-the-counter derivative structures are employed to mitigate interest rate risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Foreign Currency Risk

The Corporation's credit facilities and high yield notes are denominated in U.S. dollars and prices of the Corporation's bitumen blend are generally based on U.S. dollar market prices. Fluctuations in U.S. and Canadian dollar exchange rates may cause a negative impact on revenue, costs and debt service obligations and may have a material adverse impact on the Corporation. If over-the-counter derivative structures are employed to mitigate foreign currency risk, risks associated with such products, including counterparty risk, settlement risk, basis risk, liquidity risk and market risk, could impact or negate the hedging strategy, which would have a negative impact on the Corporation's financial position, earnings and cash flow.

Regulatory and Environmental Risk

The oil and gas industry in Canada, including the oil sands industry, operates under Canadian federal, provincial and municipal legislation and regulations. Future development of the Christina Lake Project, the Surmont Project and the Growth Properties is dependent on the Corporation maintaining its current oil sands leases and licences and receiving required regulatory approvals and permits on a timely basis. The Government of Alberta has initiated a process to control cumulative environment effects of industrial development through the Lower Athabasca Regional Plan ("LARP"). While the LARP has not had a significant effect on the Corporation, there can be no assurance that changes to the LARP or future laws or regulations will not adversely impact the Corporation's ability to develop or operate its projects.

The Corporation is committed to meeting its responsibilities to protect the environment and fully comply with all environmental laws and regulations. Alberta regulates emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("GHG"), and Canada's federal government has proposed significant extensions to its GHG regulatory requirements, which currently deal only with reporting. The direct and indirect costs of the various regulations, existing, proposed and future, may adversely affect MEG's business, operations and financial results. The emission reduction compliance obligations required under existing and future federal and provincial industrial air pollutant and GHG emission reduction targets and requirements, together with emission reduction requirements in future regulatory approvals, may not be technically or economically feasible to implement for MEG's bitumen recovery and cogeneration activities. Any failure to meet MEG's emission reduction compliance obligations may materially adversely affect MEG's business and result in fines, penalties and the suspension of operations.

Royalty Risk

The Corporation's revenue and expenses will be directly affected by the royalty regime applicable to its oil sands development. The Government of Alberta implemented a new oil and gas royalty regime effective January 1, 2009 through which the royalties for conventional oil, natural gas and bitumen are linked to price and production levels. The royalty regime applies to both new and existing oil sands projects.

Under the royalty regime, the Government of Alberta increased its royalty share from oil sands development by introducing price-sensitive formulas applied both before and after specified allowed costs have been recovered.

The Government of Alberta has publicly indicated that it intends for the revised royalty regime to be further reviewed and revised from time to time. There can be no assurances that the Government of Alberta or the Government of Canada will not adopt new royalty regimes which may render the Corporation's projects uneconomic or otherwise adversely affect its business, financial condition or results of operations.

Third Party Risks

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the Regional Municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which the Christina Lake Project, MEG's other projects and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have an adverse effect on MEG and the Christina Lake Project and MEG's other projects.

Disclosure Controls and Procedures

The Corporation's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Corporation's CEO and CFO by others, particularly during the period in which the annual filings are being prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's disclosure controls and procedures at the financial year end of the Corporation and have concluded that the Corporation's disclosure controls and procedures are effective at the financial year end of the Corporation for the foregoing purposes.

Internal Controls Over Financial Reporting

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the Corporation's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. Management's evaluation concluded that internal controls over financial reporting were effective as of December 31, 2014.

The CEO and CFO are required to cause the Corporation to disclose any change in the Corporation's internal controls over financial reporting that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Corporation's internal controls over financial reporting. No changes in internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting.

It should be noted that a control system, including the Corporation's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost/benefit relationship of possible controls and procedures.

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 AIF, 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.

Oil and Gas Information

The estimates of reserves and contingent resource estimates were prepared effective December 31, 2014 by GLJ, an independent reservoir engineering firm, in accordance with the Canadian Oil and Gas Evaluation Handbook and National Instrument 51-101.

Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Proved Reserves are also referred to as "1P Reserves".

Probable Reserves are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Proved plus probable reserves are also referred to as "2P Reserves".

Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Such contingencies include further reservoir delineation, additional facility and reservoir design work, submission of regulatory applications and the receipt of corporate approvals. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

There are three categories in evaluating Contingent Resources: Low Estimate, Best Estimate and High Estimate. The resource numbers presented all refer to the Best Estimate category. Best Estimate is a classification of resources described in the Canadian Oil and Gas Evaluation (COGE) Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate. Best Estimate Contingent Resources are also referred to as "2C Resources".

Estimates of Reserves and Resources

This document contains references to estimates of the Corporation's reserves and contingent resources. For supplemental information regarding the classification and uncertainties related to MEG's estimated reserves and resources please see "Independent Reserve and Resource Evaluation" in the AIF.

Non-GAAP Financial Measures

Certain financial measures in this MD&A 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 MEASURES" section of this MD&A.

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.

Report of Management

Management's Responsibility for the Consolidated Financial Statements

The accompanying consolidated financial statements of MEG Energy Corp. (the "Corporation") are the responsibility of Management. The consolidated financial statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include certain estimates that reflect Management's best judgments. Financial information contained throughout the annual report is consistent with these consolidated financial statements.

The Corporation maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Corporation's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that our internal controls over financial reporting were effective as of December 31, 2014.

The Corporation's Board of Directors has approved the consolidated financial statements. The Board of Directors fulfills its responsibility regarding the consolidated financial statements mainly through its Audit Committee, which is made up of three independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation. The Audit Committee meets with Management and the independent auditors at least on a quarterly basis to review and approve interim consolidated financial statements and management's discussion and analysis prior to their release as well as annually to review the annual consolidated financial statements and management's discussion and analysis and recommend their approval to the Board of Directors.

PricewaterhouseCoopers LLP, an independent firm of auditors, has been engaged, as approved by a vote of the shareholders at the Corporation's most recent Annual General Meeting, to audit and provide their independent audit opinion on the Corporation's consolidated financial statements as at and for the year ended December 31, 2014. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

W. J. McCaffrey

William (Bill) McCaffrey, P.Eng.
Chairman, President and Chief Executive Officer

Eric L. Toews, CA
Chief Financial Officer

March 3, 2015

Independent Auditor's Report

March 3, 2015

To the Shareholders of MEG Energy Corp.

We have audited the accompanying consolidated financial statements of MEG Energy Corp., which comprise the consolidated balance sheet as at December 31, 2014 and December 31, 2013 and the consolidated statements of earnings (loss) comprehensive income (loss), changes in shareholders' equity and cash flow for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditor's Responsibility

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

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of MEG Energy Corp. as at December 31, 2014 and December 31, 2013 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Accountants

Consolidated Balance Sheet

(Expressed in thousands of Canadian dollars)

As at December 31	Note	2014	2013
Assets			
Current assets			
Cash and cash equivalents	*26*	**$ 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	*15*	**178,196**	93,794
Total liabilities		**5,161,873**	4,659,311
Commitments and contingencies	*30*		
Shareholders' equity			
Share capital	*16*	**4,797,853**	4,751,374
Contributed surplus	*16*	**153,837**	126,666
Deficit		**(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 Consolidated Financial Statements.

These Consolidated Financial Statements were approved by the Corporation's Board of Directors on March 3, 2015.

W. J. McCaffrey　　Robert B. Hodgins

William (Bill) McCaffrey, Director　　**Robert B. Hodgins, Director**

Consolidated Statement of Earnings (Loss) and Comprehensive Income (Loss)

(Expressed in thousands of Canadian dollars, except per share amounts)

For the year ended December 31	Note	2014	2013
Petroleum revenue, net of royalties	*17*	**$ 2,743,987**	$ 1,270,757
Other revenue	*18*	**85,977**	63,740
		2,829,964	1,334,497
Diluent and transportation	*19*	**1,228,079**	623,648
Purchased product and storage	*20*	**163,387**	104,115
Operating expenses	*24*	**351,534**	167,586
Depletion and depreciation	*8,10*	**378,544**	189,147
General and administrative	*24*	**111,366**	92,828
Stock-based compensation	*16*	**48,310**	38,792
Research and development		**6,003**	5,588
		2,287,223	1,221,704
Revenues less expenses		**542,741**	112,793
Other income (expense)			
Interest and other income		**9,107**	22,550
Gain on disposition of assets		**–**	1,410
Foreign exchange loss, net	*21*	**(338,629)**	(180,278)
Net finance expense	*22*	**(196,858)**	(100,533)
Other expenses	*23*	**(36,123)**	–
		(562,503)	(256,851)
Loss before income taxes		**(19,762)**	(144,058)
Deferred income tax expense	*15*	**85,776**	22,347
Net loss		**(105,538)**	(166,405)
Other comprehensive income, net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**10,332**	2,858
Comprehensive loss		**$ (95,206)**	$ (163,547)
Net loss per common share			
Basic	*27*	**$ (0.47)**	$ (0.75)
Diluted	*27*	**$ (0.47)**	$ (0.75)

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

Consolidated Statement of Changes in Shareholders' Equity

(Expressed in thousands of Canadian dollars)

	Note	Share Capital	Contributed Surplus	Retained Earnings (Deficit)	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at January 1, 2014		**$ 4,751,374**	**$ 126,666**	**$ (92,493)**	**$ 2,883**	**$ 4,788,430**
Stock options exercised	*16*	**14,665**	**(3,499)**	**–**	**–**	**11,166**
RSUs vested and released	*16*	**31,814**	**(31,814)**	**1,361**	**–**	**1,361**
Stock-based compensation	*16*	**–**	**62,484**	**–**	**–**	**62,484**
Net loss		**–**	**–**	**(105,538)**	**–**	**(105,538)**
Other comprehensive income		**–**	**–**	**–**	**10,332**	**10,332**
Balance as at December 31, 2014		**$4,797,853**	**$ 153,837**	**$ (196,670)**	**$ 13,215**	**$ 4,768,235**
Balance as 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	*16*	40,522	(9,217)	–	–	31,305
RSUs vested and released	*16*	16,395	(16,395)	–	–	–
Stock-based compensation	*16*	–	50,059	–	–	50,059
Net loss		–	–	(166,405)	–	(166,405)
Other comprehensive income		–	–	–	2,858	2,858
Balance as 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 Consolidated Financial Statements.

Consolidated Statement of Cash Flow

(Expressed in thousands of Canadian dollars)

Year ended December 31	Note	2014	2013
Cash provided by (used in):			
Operating activities			
Net loss		**$ (105,538)**	$ (166,405)
Adjustments for:			
Depletion and depreciation	*8,10*	**378,544**	189,147
Stock-based compensation	*16*	**48,310**	38,792
Unrealized loss on foreign exchange	*21*	**333,149**	177,362
Unrealized gain on derivative financial liabilities	*22*	**(1,469)**	(19,256)
Inventory write-down	*7,23*	**19,668**	–
Deferred income tax expense	*15*	**85,776**	22,347
Amortization of debt issue costs	*11,13*	**10,566**	8,840
Decommissioning expenditures	*14*	**(1,893)**	(4,195)
Other		**5,997**	2,597
Net change in non-cash operating working capital items	*26*	**(5,610)**	(123,461)
Net cash provided by (used in) operating activities		**767,500**	125,768
Investing activities			
Capital investments			
Property, plant and equipment	*8*	**(1,282,194)**	(2,142,510)
Exploration and evaluation	*9*	**(7,749)**	(27,123)
Other intangible assets	*10*	**(23,571)**	(18,720)
Purchase of other assets	*11*	**(1,358)**	(41,517)
Proceeds on disposition of assets		**–**	6,801
Other		**5,778**	2,773
Net change in non-cash investing working capital items	*26*	**(3,346)**	430,316
Net cash provided by (used in) investing activities		**(1,312,440)**	(1,789,980)
Financing activities			
Issue of shares		**11,166**	31,747
Issue of long-term debt, net of issue costs		**–**	1,322,540
Repayment of long-term debt		**(14,467)**	(13,506)
Financing costs	*11*	**(10,035)**	(8,693)
Net cash provided by (used in) financing activities		**(13,336)**	1,332,088
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	*21*	**35,301**	36,353
Change in cash and cash equivalents		**(522,975)**	(295,771)
Cash and cash equivalents, beginning of year	*26*	**1,179,072**	1,474,843
Cash and cash equivalents, end of year	*26*	**$ 656,097**	$ 1,179,072

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

Year ended December 31, 2014

(All amounts are expressed in thousands of Canadian dollars, unless otherwise noted)

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 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

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). These consolidated financial statements were approved by the Corporation's Board of Directors on March 3, 2015.

3. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of measurement

The consolidated financial statements have been prepared on the historical cost basis, except for the revaluation of certain financial assets and financial liabilities to fair value, including derivative financial instruments, which are measured at fair value.

(b) Basis of consolidation

The consolidated financial statements of the Corporation comprise the Corporation and its wholly-owned subsidiary, MEG Energy (U.S.) Inc., which was incorporated in 2012. Earnings and expenses of its subsidiary are included in the consolidated statement of earnings (loss) and comprehensive income (loss). All intercompany transactions, balances, income and expenses 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.

(c) Operating segments

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.

(d) Foreign currency translation

i. Functional and presentation currency

Items included in the consolidated financial statements are measured using the currency of the primary economic environment in which the Corporation operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars ($ or C$), which is the Corporation's functional currency.

ii. Transactions and balances

Foreign currency transactions are translated into Canadian dollars at exchange rates prevailing at the dates of the transactions. Monetary assets and liabilities denominated in a foreign currency are translated into Canadian dollars at rates of exchange in effect at the end of the period. Foreign currency differences arising on translation are recognized in earnings or loss.

For the purposes of presenting consolidated financial statements, the assets and liabilities of the foreign subsidiary are translated into Canadian dollars at rates of exchange in effect at the end of the period. Earnings and expense items are translated at the average exchange rates prevailing at the dates of the transactions. Exchange differences arising, if any, are recognized in other comprehensive income.

(e) Joint operations

The Corporation owns an undivided 50% working interest in Access Pipeline and is responsible for its proportionate ownership interest of all assets and liabilities and other obligations. Since the Corporation owns an undivided interest in Access Pipeline, it holds a proportionate share of the rights to the assets and obligations for the liabilities. As a result, the Corporation presents its proportionate share of the assets, liabilities, revenues and expenses of Access Pipeline on a line-by-line basis in the consolidated financial statements.

(f) Financial instruments

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or have been transferred and the Corporation has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

At initial recognition, the Corporation classifies its financial instruments in the following categories depending on the purpose for which the instruments were acquired:

i. Financial assets and liabilities at fair value through earnings or loss

A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short term. Derivative financial instruments are also included in this category unless they are designated as hedges. The Corporation's investments in U.S. auction rate securities ("ARS") are classified as fair value through earnings or loss.

Financial instruments in this category are recognized initially and subsequently at fair value. Transaction costs are expensed in the consolidated statement of earnings (loss) and comprehensive income (loss). Gains and losses arising from changes in fair value are presented in earnings or loss within net finance expense in the period in which they arise. Financial assets and liabilities at fair value through earnings or loss are classified as current except for any portion expected to be realized or paid beyond twelve months from the balance sheet date.

ii. Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Corporation's loans and receivables are comprised of cash and cash equivalents and trade receivables and other, and are included in current assets due to their short-term nature.

Loans and receivables are initially recognized at the amount expected to be received less any required discount to reduce the loans and receivables to fair value. Subsequently, loans and receivables are measured at amortized cost using the effective interest method less any provision for impairment.

iii. Financial liabilities at amortized cost

Financial liabilities at amortized cost include accounts payable and accrued liabilities and long-term debt. Accounts payable and accrued liabilities are initially recognized at the amount required to be paid less any required discount to reduce the payables to fair value. Long-term debt is recognized initially at fair value, net of any transaction costs incurred, and subsequently at amortized cost using the effective interest method.

Financial liabilities are classified as current liabilities if payment is due within twelve months. Otherwise, they are presented as non-current liabilities.

iv. Derivative financial instruments

The Corporation may use derivatives in the form of interest rate swaps and floors to manage risks related to its variable rate debt. All derivatives have been classified at fair value through earnings or loss. Derivative financial instruments are included on the balance sheet within provisions and other liabilities and are classified as current or non-current based on the contractual terms specific to the instrument.

Gains and losses on re-measurement of derivatives related to finance activities are included in net finance expense in the period in which they arise.

(g) Cash and cash equivalents

Cash and cash equivalents include cash on hand, deposits held with banks, and other short-term highly liquid investments such as commercial paper, money market deposits or similar instruments, with a maturity of 90 days or less.

(h) Short-term investments

Short-term investments consist of commercial paper, money market deposits or similar instruments with a maturity of between 91 and 365 days.

(i) Trade receivables and other

Trade receivables are recorded based on the Corporation's revenue recognition policy as described in note 3(t). If applicable, an allowance for doubtful accounts is recorded to provide for specific doubtful receivables. Other amounts include deposits and advances which include funds placed in escrow in accordance with the terms of certain agreements, funds held in trust in accordance with governmental regulatory requirements and funds advanced to joint venture partners.

(j) Inventories

Product inventories consist of crude oil products and are valued at the lower of cost and net realizable value on a weighted average cost basis. Costs include direct and indirect expenditures incurred in bringing an item or product to its existing condition and location. Net realizable value is the estimated selling price less applicable selling expenses. If the carrying value exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if the inventory is still on hand but the circumstances which caused the write-down no longer exist.

(k) Property, plant and equipment and exploration and evaluation assets

i. Recognition and measurement

Exploration and evaluation ("E&E") expenditures, including the costs of acquiring licenses and directly attributable general and administrative costs, initially are capitalized as exploration and evaluation assets. The costs are accumulated in cost centres pending determination of technical feasibility and commercial viability. Costs incurred prior to obtaining a legal right or license to explore are expensed in the period in which they are incurred.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units ("CGUs").

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. A review of each project area is carried out, at least annually, to ascertain whether proved or probable reserves have been discovered. Upon determination of proved or probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to property, plant and equipment. If it is determined that an E&E asset is not technically feasible or commercially viable and the Corporation decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to expense.

Development and production items of property, plant and equipment, which include oil sands development, production, transportation and storage assets are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development, production, transportation and storage assets are grouped into CGUs for impairment testing. A CGU is the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. When significant parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components).

Borrowing costs incurred for the construction of a qualifying asset are capitalized when a substantial period of time is required to complete and prepare the asset for its intended use. All other borrowing costs are recognized over the term of the related debt facility as an expense using the effective interest method. The Corporation capitalizes overhead and administrative expenses that are directly attributable to bringing qualifying assets into operation.

ii. Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as crude oil, transportation and storage assets only when it is probable that future economic benefits associated with the item will flow to the Corporation and the cost of the item can be measured reliably. Such capitalized crude oil, transportation and storage assets generally represent costs incurred in developing proved and/or probable reserves and enhancing production from such reserves. All other expenditures are recognized in earnings or loss as incurred.

iii. Depletion and depreciation

The net carrying value of field production assets are depleted using the unit-of-production method by reference to the ratio of production in the year to the related proved reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

The net carrying value of major facilities and equipment are depreciated on a unit-of-production basis over the total productive capacity of the facilities. Where significant components of development or production assets have different useful lives, they are accounted for and depreciated as separate items of property, plant and equipment.

The net carrying values of transportation and storage equipment are depreciated on a straight-line basis over their estimated fifty year useful lives.

Corporate assets consist primarily of office equipment and leasehold improvements and are stated at cost less accumulated depreciation. Depreciation of office equipment is provided over the useful life of the assets on the declining balance basis at 25% per year. Leasehold improvements are depreciated on a straight-line basis over the term of the lease.

Assets under construction are not subject to depletion and depreciation.

(l) Other intangible assets

Other intangible assets acquired by the Corporation which have a finite useful life are carried at cost less accumulated depreciation. Subsequent expenditures are capitalized only to the extent that they increase the future economic benefits embodied in the asset to which they relate. The Corporation incurs costs associated with research and development. Expenditures during the research phase are expensed. Expenditures during the development phase are capitalized only if certain criteria, including technical feasibility and the intent to develop and use the technology, are met. If these criteria are not met, the costs are expensed as incurred. The cost associated with purchasing or creating software which is not an integral component of the related computer hardware is included within other intangible assets. The net carrying value of software is amortized over the useful life of the asset on the declining balance basis at 25% per year.

(m) Other assets – long-term pipeline linefill

The Corporation has entered into agreements to transport bitumen blend and diluent on third-party pipelines for which it is required to supply linefill. 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 either a current or long-term asset based on the term of the related transportation contract. The linefill is carried at the lower of cost or net realizable value. If the carrying value exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if the circumstances which caused the write-down no longer exist.

(n) Leased assets

Leases where the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term to produce a constant periodic rate of interest on the remaining balance of the liability.

All other leases are operating leases, which are not recognized on the Corporation's balance sheet. Payments made under operating leases are recognized as an expense as incurred over the term of the lease.

When lease inducements are received to enter into operating leases, such inducements are recognized as a deferred liability. The aggregate benefit of inducements is recognized as a reduction of the related lease expense on a straight-line basis, except where another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

(o) Impairments

i. Financial assets

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

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

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

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

ii. Non-financial assets

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

For the purpose of impairment testing, assets are grouped into CGUs. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell. E&E assets are assessed for impairment within the aggregation of all CGUs in that segment.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves. Fair value less costs to sell is defined as the amount obtainable from the sale of an asset or CGU in an arm's length transaction between knowledgeable, willing parties, less the costs of disposal.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in earnings or loss. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro-rata basis.

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

(p) Provisions

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

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

The decommissioning provision is measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the decommissioning provision is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation as well as any changes in the discount rate. Increases in the decommissioning provision due to the passage of time are recognized as a finance expense whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the obligations are charged against the decommissioning provision.

(q) Deferred income taxes

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

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

(r) Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of shares are recognized as a reduction of shareholders' equity, net of any income tax.

(s) Share based payments

The Corporation's Stock Option Plan and Restricted Share Unit Plan each allow for the granting of stock options and restricted share units ("RSUs"), including performance share units ("PSUs") to directors, officers, employees and consultants. The grant date fair value of stock options, RSUs and PSUs granted is recognized as stock-based compensation expense, with a corresponding increase in contributed surplus, over the vesting period of the options, RSUs and PSUs, respectively. Each tranche in an award is considered a separate grant with its own vesting period and grant date fair value. Fair value is determined using the Black-Scholes option pricing model. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options, RSUs and PSUs that vest. The Corporation's RSU Plan allows the holder of an RSU or PSU to receive a cash payment or its equivalent in fully-paid common shares, at the Corporation's discretion, equal to the fair market value of the Corporation's common shares calculated at the date of such payment. The Corporation does not intend to make cash payments under the RSU Plan and, as such, the RSUs and PSUs are accounted for within shareholders' equity.

(t) Revenues

Petroleum revenue and royalty recognition:

Revenue associated with the sale of proprietary and purchased crude oil and natural gas owned by the Corporation is recognized when title passes from the Corporation to its customers. Royalties are recorded at the time of production.

Other revenue recognition:

Revenue from power generated in excess of the Corporation's internal requirements is recognized when the power leaves the plant gate, at which point the risks and rewards are transferred to the customer. Revenue generated from the transportation of crude oil products is recognized in the period the product is delivered and the service is provided.

(u) Diluent and transportation

The costs associated with the transportation of crude oil, including the cost of diluent used in blending, are recognized when the product is sold.

(v) Purchased product and storage

Purchased product and storage costs include the cost of crude oil products purchased from third parties and associated transportation and storage costs.

(w) Net finance expense

Net finance expense is comprised of interest expense on borrowings, accretion of the discount on provisions, and gains and losses on derivative financial instruments and other assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time required to complete and prepare the assets for their intended use. All other borrowing costs are recognized in finance expense using the effective interest method.

(x) Net earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing the net earnings (loss) for the period attributable to common shareholders of the Corporation by the weighted average number of common shares outstanding during the period.

Diluted earnings (loss) per share is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to options, RSUs and PSUs is computed using the treasury stock method. The Corporation's potentially dilutive instruments comprise stock options, RSUs and PSUs granted to directors, officers, employees and consultants.

(y) New accounting standards adopted during the year

The Corporation has adopted the following revised standards effective January 1, 2014. These changes, along with the corresponding 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.

i. 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.

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

(z) Accounting standards issued but not yet applied

The IASB has issued the following standards which have not yet been adopted by the Corporation: IFRS 9, Financial Instruments; and IAS 15, Revenue From Contracts With Customers. The Corporation is currently assessing the impact of the adoption of these standards on the Corporation's consolidated financial statements.

The following is a brief summary of the new and amended standards:

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.

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.

4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGMENTS

The timely preparation of the consolidated financial statements requires that management make estimates and assumptions and use judgment regarding the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur. Significant judgments, estimates and assumptions made by management in the preparation of these consolidated financial statements are outlined below.

(a) Property, plant and equipment

Field production assets within property, plant and equipment are depleted using the unit-of-production method based on estimates of proved bitumen reserves and future costs required to develop those reserves. There are a number of inherent uncertainties associated with estimating reserves. By their nature, these estimates of reserves, including the estimates of future prices and costs, and related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

Amounts recorded for depreciation of major facilities, transportation and storage equipment are based on management's best estimate of their useful lives. Accordingly, those amounts are subject to measurement uncertainty.

In addition, management is required to make estimates and assumptions and use judgment regarding the timing of when major development projects are ready for their planned use, which also determines when these assets are subject to depletion and depreciation.

(b) Exploration and evaluation assets

The application of the Corporation's accounting policy for exploration and evaluation expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

(c) Bitumen reserves

The estimation of reserves involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Corporation expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion and depreciation charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of property, plant and equipment carrying amounts.

(d) Joint control

Judgment is required to determine whether an interest the Corporation holds in a joint arrangement should be classified as a joint operation or joint venture. The determination includes an assessment as to whether the Corporation has the rights to the assets and obligations for the liabilities of the arrangement or the rights to the net assets.

(e) Decommissioning provision

Decommissioning costs are incurred when certain of the Corporation's tangible long-lived assets are retired. Assumptions, based on current economic factors which management believes are reasonable, have been made to estimate the future liability. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. The impact to net earnings over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, management exercises judgment to determine the appropriate discount rate at the end of each reporting period. This discount rate, which is a credit-adjusted risk-free rate, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

(f) Impairments

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures, and the way in which management monitors the Corporation's operations.

The recoverable amounts of CGUs and individual assets have been determined as the higher of the CGUs or the asset's fair value less costs to sell and its value in use. These calculations require the use of estimates and assumptions and are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

(g) Stock-based compensation

Amounts recorded for stock-based compensation expense are based on several assumptions including the risk-free interest rate, the forfeiture rate, the expected volatility of the Corporation's share price and those of similar publicly listed enterprises, which may not be indicative of future volatility. Accordingly, those amounts are subject to measurement uncertainty.

(h) Deferred income taxes

Tax regulations and legislation and the interpretations thereof in which the Corporation operates are subject to change. As such, income taxes are subject to measurement uncertainty.

The Corporation follows the liability method of accounting for income taxes. Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. The periods in which timing differences reverse are impacted by future earnings and capital expenditures. Rates are also affected by changes to tax legislation. Income taxes are recognized in net earnings except to the extent that they relate to items recognized directly in shareholders' equity, in which case the income taxes are recognized in shareholders' equity.

The Corporation also makes interpretations and judgments on the application of tax laws for which the eventual tax determination may be uncertain. To the extent that interpretations change, there may be a significant impact on the consolidated financial statements.

(i) Derivative financial instruments

The estimated fair values of financial assets and liabilities, by their very nature, are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Corporation may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

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, ARS, 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 the fair value of the respective assets and liabilities 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 and foreign exchange rates. The observable inputs may be adjusted using certain methods, which include extrapolation to the end of the term of the contract.

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.

Movement in level 3 instruments during the year:

	ARS
Balance as at December 31, 2013	$ 2,252
Transfer to Level 2	(2,252)
Balance as at December 31, 2014	**$ –**

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 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 – $nil).

(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 versus 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

As at December 31, 2014, a 100 basis points increase in LIBOR on floating rate debt, excluding the impact of interest capitalized, would have resulted in a C$1.4 million decrease in net earnings before income taxes (December 31, 2013 – C$1.4 million). As at December 31, 2014, a 100 basis points decrease in LIBOR, excluding the impact of interest capitalized, would have resulted in no impact on net earnings before income taxes (December 31, 2013 – $nil).

(c) Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Corporation's financial assets or liabilities. The Corporation has US dollar denominated long-term debt as described in note 13.

As at December 31, 2014, a $0.01 change in the US dollar to Canadian dollar exchange rate would have resulted in a corresponding change in the carrying value of long-term debt of C$38.1 million (December 31, 2013 – C$38.3 million).

(d) Commodity price risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. The Corporation's financial results may be significantly impacted by factors outside of the Corporation's control, including commodity prices and heavy oil differentials. Future fluctuations in commodity prices will affect the amount of revenue earned by the Corporation on the sale of its bitumen production and will impact the amount the Corporation pays for natural gas, electricity and diluent, which are all inputs into the steam-assisted gravity drainage production and transportation process. The Corporation does not currently have any derivative commodity contracts in place.

(e) Credit risk

Credit risk arises from the potential that the Corporation may incur a loss if a counterparty fails to meet its obligations in accordance with agreed terms. This credit risk exposure is mitigated through the use of credit policies governing the Corporation's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. A substantial portion of accounts receivable are with investment grade customers in the energy industry and are subject to normal industry credit risk. All transactions with financial institutions are made with those that have investment grade credit ratings. At December 31, 2014, the Corporation's estimated maximum exposure to credit risk related to trade receivables, deposits and advances was $172.9 million. There were no significant trade receivables which were greater than 90 days as at December 31, 2014.

The Corporation's cash balances are used to fund the development of its oil sands properties. As a result, the primary objectives of the investment portfolio are low risk capital preservation and high liquidity. The cash balances are held in high interest savings accounts or are invested in high grade liquid short-term debt such as commercial, government and bank paper. The cash and cash equivalents balance at December 31, 2014 was $656.1 million. None of the investments are past their maturity or considered impaired. The Corporation's estimated maximum exposure to credit risk related to its cash and cash equivalents is $656.1 million.

The Corporation's investments in ARS are subject to the credit risk associated with the counterparties to the investments. The Corporation's estimated maximum exposure to credit risk related to its investments in ARS is $2.9 million.

(f) Liquidity risk

Liquidity risk is the risk that the Corporation will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk that the Corporation cannot earn enough income from the Christina Lake Project or is unable to raise further capital in order to meet its obligations under its debt agreements. The lenders are entitled to exercise any and all remedies available under the debt agreements. The Corporation manages its liquidity risk through the active management of cash, debt and revolving credit facilities and by maintaining appropriate access to credit.

The future undiscounted financial obligations of the Corporation are noted below:

As at December 31, 2014	**Total**	**Less than 1 year**	**1 – 3 years**	**4 – 5 years**	**More than 5 years**
Long-term debt	**$ 4,421,721**	**$ 15,081**	**$ 30,162**	**$ 30,162**	**$ 4,346,316**
Interest on long-term debt	**1,862,853**	**251,735**	**501,922**	**499,511**	**609,685**
Derivative financial liabilities	**29,511**	**15,538**	**8,024**	**5,949**	**–**
Accounts payable and accrued liabilities	**366,374**	**366,374**	**–**	**–**	**–**
	$ 6,680,459	**$ 648,728**	**$ 540,108**	**$ 535,622**	**$ 4,956,001**

As at December 31, 2013	**Total**	**Less than 1 year**	**1 – 3 years**	**4 – 5 years**	**More than 5 years**
Long-term debt	$ 4,067,738	$ 13,827	$ 27,654	$ 27,654	$ 3,998,603
Interest on long-term debt	1,938,494	231,313	461,208	458,997	786,976
Derivative financial liabilities	30,981	13,886	13,054	3,161	880
Accounts payables and accrued liabilities	359,724	359,724	–	–	–
	$ 6,396,937	$ 618,750	$ 501,916	$ 489,812	$ 4,786,459

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 (2013 – $601.2 million) in inventory product costs were charged to earnings through diluent and transportation expense.

During the 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[a]	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[a]	1,045,704	296,248	6,082	1,348,034
Transfer to other assets *(note 9)*	–	(12,381)	–	(12,381)
Balance as at December 31, 2014	**$ 7,539,369**	**$ 1,560,314**	**$ 47,117**	**$ 9,146,800**
Accumulated depletion and depreciation				
Balance as at December 31, 2012	$ 329,556	$ 22,831	$ 6,591	$ 358,978
Depletion and depreciation for the year[b]	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[b]	370,301	19,661	5,152	395,114
Balance as at December 31, 2014	**$ 883,723**	**$ 51,113**	**$ 16,474**	**$ 951,310**
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 $8.5 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 utilizing a weighted average capitalization rate of 7.2% (year ended December 31, 2013 – $76.5 million; weighted average capitalization rate – 6.0%). 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 at December 31, 2014 no impairment has been recognized on property, plant and equipment.

9. EXPLORATION AND EVALUATION ASSETS

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

(a) Additions include $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.

(b) Exploration and evaluation assets were transferred to property, plant and equipment following the determination of technical feasibility and commercial viability of the Surmont Project.

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)
Less unamortized financial derivative liability discount	**(17,514)**	(20,565)
Less 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 year-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.

Required debt principal repayments	2015	2016	2017	2018	2019	Thereafter
	$ 15,081	$ 15,081	$ 15,081	$ 15,081	$ 15,081	$ 4,346,316

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 and cash equivalents 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)) and these interest rate swap contracts expire on 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.

As at December 31, 2014, a 1% increase in the credit-adjusted risk-free rate would result in a $21.3 million decrease in the present value of the decommissioning provision.

(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. DEFERRED INCOME TAXES

The deferred tax provisions differ from results which would be obtained had the Corporation applied the combined federal and provincial statutory rates of 25% (2013 – 25%) to earnings. The reasons for these differences are as follows:

For the years ended December 31	**2014**	**2013**
Expected income tax recovery	**$ (4,940)**	$ (36,014)
Add (deduct) the tax effect of:		
Stock-based compensation	**12,077**	9,698
Non-taxable loss on foreign exchange	**46,056**	26,715
Taxable capital losses not recognized	**46,056**	21,498
Tax benefit of vested RSUs	**(13,783)**	–
Other	**310**	450
	$ 85,776	$ 22,347

The analysis of deferred tax assets and deferred tax liabilities is as follows:

As at December 31	**2014**	**2013**
Deferred tax liabilities:		
Deferred tax liabilities to be recovered after more than 12 months	**$ 878,888**	$ 723,016
Deferred tax liabilities to be recovered within 12 months	**–**	1,783
	878,888	724,799
Deferred tax assets:		
Deferred tax assets to be recovered after more than 12 months	**(694,500)**	(627,328)
Deferred tax assets to be recovered within 12 months	**(6,192)**	(3,677)
	(700,692)	(631,005)
Deferred tax liabilities (net)	**$ 178,196**	$ 93,794

The net movement within the deferred income tax liability is as follows:

	2014	**2013**
Balance as at January 1	**$ 93,794**	$ 71,444
Charged to the statement of earnings (loss)	**85,776**	22,347
Credited to other comprehensive income	**(13)**	(23)
Tax credited directly to equity	**(1,361)**	26
Balance as at December 31	**$ 178,196**	$ 93,794

The movements in deferred income tax assets and liabilities during the years are as follows:

Deferred tax liabilities	**Property, plant and equipment**	**Other**	**Total**
Balance as at January 1, 2013	$ 542,075	$ –	$ 542,075
Charged to the statement of earnings (loss)	178,383	4,315	182,698
Charged to equity	–	26	26
Balance as at December 31, 2013	$ 720,458	$ 4,341	$ 724,799
Charged to the statement of earnings (loss)	151,221	2,868	154,089
Balance as at December 31, 2014	**$ 871,679**	**$ 7,209**	**$ 878,888**

Deferred tax assets	**Tax losses**	**Derivative financial liabilities**	**Provisions**	**Other**	**Total**
Balance as at January 1, 2013	$ (451,203)	$ (9,298)	$ (349)	$ (9,781)	$ (470,631)
Charged (credited) to the statement of earnings (loss)	(169,781)	1,553	(142)	8,019	(160,351)
Credited to other comprehensive income	–	–	–	(23)	(23)
Balance as at December 31, 2013	$ (620,984)	$ (7,745)	$ (491)	$ (1,785)	$ (631,005)
Charged (credited) to the statement of earnings (loss)	(63,160)	367	(661)	(4,859)	(68,313)
Credited to other comprehensive income	–	–	–	(13)	(13)
Credited to equity	(1,361)	–	–	–	(1,361)
Balance as at December 31, 2014	**$ (685,505)**	**$ (7,378)**	**$ (1,152)**	**$ (6,657)**	**$ (700,692)**

As at December 31, 2014, the Corporation had approximately $7.0 billion in available tax pools (December 31, 2013 – $6.8 billion). Included in the tax pools are $2.7 billion of non-capital loss carry forward balances ($0.2 billion expiring in 2026; $0.2 billion expiring in 2027; $0.3 billion expiring in 2028; $0.5 billion expiring in 2029; $0.3 billion expiring in 2030 and $1.2 billion expiring after 2030). In addition, as at December 31, 2014, the Corporation had an additional $0.9 billion (December 31, 2013 – $0.5 billion) of capital investment in incomplete projects which will serve to increase available tax pools upon completion of the projects.

16. 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 by the third anniversary of the grant date 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

As at December 31, 2014	**Outstanding**			**Vested**		
Range of exercise prices	**Options**	**Weighted average exercise price**	**Weighted average remaining life** *(in years)*	**Options**	**Weighted average exercise price**	**Weighted average remaining life** *(in years)*
$22.20 – $29.99	1,211,757	$ 24.02	1.74	1,173,956	$ 24.02	1.59
$30.00 – $39.99	5,452,825	34.72	5.15	2,152,976	33.93	4.07
$40.00 – $49.99	609,340	41.74	1.36	596,243	41.72	1.29
$50.00 – $51.43	591,866	51.42	3.43	591,866	51.42	3.43
	7,865,788	$ 34.87	4.20	4,515,041	$ 34.67	2.97

The fair value of each option granted during the year ended December 31, 2014 and 2013 is estimated on the date of the grant using the Black-Scholes option pricing model with weighted average assumptions for grants as follows:

	2014	2013
Risk-free rate	**1.55%**	1.57%
Expected lives	**5 years**	5 years
Volatility	**31%**	36%
Annual dividend per share	**$ nil**	$ nil
Fair value of options granted	**$ 11.66**	$ 10.54

(d) Restricted share units 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.

	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

17. PETROLEUM REVENUE, NET OF ROYALTIES

For the years ended December 31	2014	2013
Petroleum revenue:		
Proprietary	**$ 2,701,801**	$ 1,207,650
Third party[a]	**149,260**	101,750
	2,851,061	1,309,400
Royalties	**(107,074)**	(38,643)
Petroleum revenue, net of royalties	**$ 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".

18. OTHER REVENUE

For the years ended December 31	2014	2013
Power revenue	**$ 55,352**	$ 44,456
Transportation revenue	**30,625**	19,284
Other revenue	**$ 85,977**	$ 63,740

19. DILUENT AND TRANSPORTATION

For the years ended December 31	2014	2013
Diluent	**$ 1,163,637**	$ 601,191
Transportation	**64,442**	22,457
Diluent and transportation	**$ 1,228,079**	$ 623,648

20. PURCHASED PRODUCT AND STORAGE

For the years ended December 31	2014	2013
Purchased product and storage	$ 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".

21. FOREIGN EXCHANGE LOSS, NET

For the years ended December 31	2014	2013
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (368,450)**	$ (213,715)
US$ denominated cash and cash equivalents	**35,301**	36,353
Unrealized loss on foreign exchange	**(333,149)**	(177,362)
Realized loss on foreign exchange	**(5,480)**	(2,916)
Net foreign exchange loss	**$ (338,629)**	$ (180,278)

22. NET FINANCE EXPENSE

For the years ended December 31	2014	2013
Total interest expense	$ 265,140	$ 186,835
Less capitalized interest	(75,975)	(76,529)
Net interest expense	189,165	110,306
Accretion on decommissioning provision	4,535	4,763
Unrealized fair value gain on embedded derivative liabilities	(2,652)	(14,352)
Unrealized fair value (gain) loss on interest rate swaps	1,183	(4,904)
Realized loss on interest rate swaps	5,056	4,720
Unrealized fair value gain on other assets	(429)	–
Net finance expense	$ 196,858	$ 100,533

23. OTHER EXPENSES

For the years ended December 31	2014	2013
Inventory write-down [a]	$ 19,668	$ –
Contract cancellation costs [b]	16,455	–
Other expenses	$ 36,123	$ –

(a) During the 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 (year ended December 31, 2013 – $nil).

(b) During the 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 (year ended December 31, 2013 – $nil).

24. WAGES AND EMPLOYEE BENEFITS EXPENSE

For the years ended December 31	2014	2013
Operating expense:		
Salaries and wages	$ 59,157	$ 37,994
Short-term employee benefits	6,196	3,753
General and administrative expense:		
Salaries and wages	80,875	67,621
Short-term employee benefits	10,801	10,616
	$ 157,029	$ 119,984

25. TRANSACTIONS WITH RELATED PARTIES

The only related party transactions during the year ended December 31, 2014, was the compensation of key management personnel. The Corporation considers directors and officers of the Corporation as key management personnel.

For the years ended December 31	2014	2013
Salaries and short-term employee benefits	$ 9,975	$ 9,230
Share-based compensation expense	13,539	12,477
	$ 23,514	$ 21,707

During the year ended December 31, 2013, the Corporation paid $0.3 million in costs on behalf of WP Lexington Private Equity B.V. ("WP Lex"). WP Lex is considered to be a related party of the Corporation as two managing directors of WP Lex also hold positions as members of the Board of Directors of the Corporation.

26. SUPPLEMENTAL CASH FLOW DISCLOSURES

As at December 31	2014	2013
Changes in non-cash working capital		
Operating activities:		
Trade receivables and other	**$ 9,941**	$ (75,107)
Inventories[a]	**(30,519)**	(105,276)
Accounts payable and accrued liabilities	**14,968**	56,922
Change in operating non-cash working capital	**(5,610)**	(123,461)
Investing activities:		
Short-term investments	**–**	532,998
Accounts payable and accrued liabilities	**(3,346)**	(103,711)
Trade receivables and other	**–**	1,029
Change in investing non-cash working capital	**(3,346)**	430,316
Change in total non-cash working capital	**$ (8,956)**	$ 306,855
Cash and cash equivalents:[b]		
Cash	**$ 273,846**	$ 1,065,179
Cash equivalents	**382,251**	113,893
	$ 656,097	$ 1,179,072
Cash interest paid	**$ 236,410**	$ 149,925
Cash interest received	**$ 7,358**	$ 12,446

(a) The December 31, 2014 amount excludes a non-cash decrease in inventory of $7.1 million (December 31, 2013 – increase of $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 have been translated into Canadian dollars at the year-end exchange rate of US$1 = C$1.1601 (December 31, 2013 – US$1 = C$1.0636).

27. EARNINGS (LOSS) PER COMMON SHARE

For the years ended December 31	2014	2013
Net loss	**$ (105,538)**	$ (166,405)
Weighted average common shares outstanding	**223,314,791**	221,800,594
Dilutive effect of stock options, RSUs and PSUs[a]	**–**	–
Weighted average common shares outstanding – diluted	**223,314,791**	221,800,594
Net earnings (loss) per common share, basic	**$ (0.47)**	$ (0.75)
Net earnings (loss) per common share, diluted	**$ (0.47)**	$ (0.75)

(a) For the years ended December 31, 2014 and December 31, 2013, 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 had recognized net earnings during the year ended December 31, 2014, the dilutive effect of stock options, RSUs and PSUs would have been 1,371,687 (year ended December 31, 2013 – 2,508,677).

28. 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 year ended December 31, 2014, petroleum revenue related to operations in the United States was $131.4 million (year ended December 31, 2013 – $97.6 million).

29. JOINT OPERATIONS

The Corporation transports its bitumen blend volumes and diluent purchases on pipelines that are operated by Access Pipeline. The Corporation has an undivided 50% interest in this jointly controlled entity and presents its proportionate share of the assets, liabilities, revenues and expenses of the joint operation on a line-by-line basis in the consolidated financial statements. As at December 31, 2014, the Corporation's proportionate interest in the joint operation's working capital balances was $24.6 million (December 31, 2013 – $16.9 million) and its interest in related pipeline assets, recorded in property, plant and equipment, was $1.1 billion (December 31, 2013 – $812.1 million).

Operating commitments of $5.0 million and capital commitments of $1.9 million related to the joint operation are included within "Commitments" presented within Note 30.

30. 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 $46.4 million in 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.

31. CAPITAL DISCLOSURES

As at December 31, 2014, the Corporation's capital resources included $525.5 million of working capital, an additional undrawn US$2.5 billion syndicated revolving credit facility and a US$500.0 million guaranteed letter of credit facility under which US$164.8 million of letters of credit have been issued. Working capital is comprised of $656.1 million of cash and cash equivalents, offset by a non-cash working capital deficiency of $130.6 million.

The Corporation's cash is held in high interest savings accounts with a diversified group of highly-rated financial institutions. The Corporation has also invested in high grade, liquid, short-term instruments such as government, commercial and bank paper as well as term deposits. To date, the Corporation has experienced no material loss or lack of access to its cash in operating accounts, invested cash or cash equivalents. However, the Corporation can provide no assurance that access to its invested cash and cash equivalents will not be impacted by adverse conditions in the financial markets. While the Corporation monitors the cash balances in its operating and investment accounts according to its investment policy and adjusts the cash balances as appropriate, these cash balances could be impacted if the underlying financial institutions or corporations fail or are subject to other adverse conditions in the financial markets.

Directors and Officers

Board of Directors

Boyd Anderson [1,3]
Lead Director, Independent

Harvey Doerr [1,3]
Governance and Nominating
Committee Chair, Independent

Robert B. Hodgins [1,2]
Audit Committee Chair, Independent

Peter R. Kagan [3]
Independent

David B. Krieger [1,2]
Independent

William (Bill) McCaffrey
Chairman, President and
Chief Executive Officer, Non-Independent

Jeffrey J. McCaig [2,3]
Independent

James D. McFarland [2,3]
Compensation Committee Chair, Independent

David J. Wizinsky [4]
Corporate Secretary, Non-Independent

1 Audit Committee
2 Compensation Committee
3 Governance and Nominating Committee
4 Mr. Wizinsky is not standing for re-election to the Board of Directors at the May 2015 meeting of shareholders.

Detailed biographies of MEG's Board of Directors and Corporate Officers are available on the corporation's website at **www.megenergy.com**

Corporate Officers

William (Bill) McCaffrey
Chairman, President and Chief Executive Officer

Eric L. Toews
Chief Financial Officer

Grant Boyd
Senior Vice President, Resource Management – Growth Properties

Jamey Fitzgibbon
Senior Vice President, Resource Management – Christina Lake and Special Projects

Don Moe
Senior Vice President, Supply and Marketing

Richard Sendall
Senior Vice President,
Strategy and Government Relations

Chi-Tak Yee
Senior Vice President,
Reservoir and Geosciences

Grant Borbridge
Vice President, Legal and General Counsel

Scott Carrothers
Vice President, Finance and Treasurer

Stephen Diotte
Vice President, Human Resources,
Information Technology and Corporate Services

John Nearing
Vice President, Finance and Controller

John Rogers
Vice President, Investor Relations
and External Communications

Chris Sloof
Vice President, Projects

Don Sutherland
Vice President, Regulatory
and Community Relations

David J. Wizinsky
Corporate Secretary

Information for Shareholders

MEG Energy Corp. shares are traded on the Toronto Stock Exchange under the symbol "MEG".

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Auditor

PricewaterhouseCoopers LLP

Independent Reserve Evaluator

GLJ Petroleum Consultants

Annual Meeting of Shareholders

May 7, 2015
Bow Glacier Room
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3rd Floor, 250 – 5th Street SW
Calgary, Alberta

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