FIRST QUARTER 2018

Report to Shareholders for the period ended March 31, 2018

MEG Energy Corp. reported first quarter 2018 operating and financial results on May 10, 2018. Highlights include:

- Record first quarter production volumes of 93,207 barrels per day (bpd), reflecting the continued ramp-up of MEG's eMSAGP growth initiative at Christina Lake Phase 2B;
- First quarter non-energy operating costs of $4.55 per barrel and net operating costs of $5.98 per barrel;
- The repayment of approximately $1.225 billion of MEG's senior secured term loan from the majority of the $1.5 billion net cash proceeds received from the sale of the company's interest in the Access Pipeline and Stonefell Terminal. The remaining $275 million is allocated towards fully funding MEG's previously announced 13,000 bpd brownfield expansion at Christina Lake Phase 2B;
- Total cash capital investment of $148 million, mainly directed towards advancing the company's objective to reach 113,000 bpd in 2020; and
- Cash and cash equivalents of $675 million. MEG's four-year covenant-lite US$1.4 billion credit facility remains undrawn.

MEG's growth is proceeding on schedule and on budget, with the eMSAGP implementation expected to be completed later this year bringing production to 100,000 bpd by early 2019. The company anticipates the Phase 2B brownfield expansion to increase production capacity to approximately 113,000 bpd in 2020. MEG continues to target 2018 average production of 85,000 to 88,000 bpd and 2018 exit production of 95,000 to 100,000 bpd. The 2018 average production guidance takes into account a planned maintenance turnaround at Christina Lake Phase 2B scheduled for the second quarter.

"Taking into consideration the market dynamics in the first quarter of 2018, MEG delivered solid operating and financial results," said Bill McCaffrey, President and Chief Executive Officer. "We were able to effectively mitigate pipeline apportionment issues by utilizing the network of storage and rail facilities we have available to us, and we continue to have good access to the Gulf Coast via the Flanagan South and Seaway pipeline systems, which enables us to sell a significant percentage of our barrels at world prices."

MEG's current contract of 50,000 bpd of transportation capacity on Flanagan South and Seaway will double to 100,000 bpd in mid-2020, moving approximately two-thirds of the company's forecast blend sales volume to the Gulf Coast and world pricing. This combination of growing pipeline access and continued optionality around rail advances MEG's strategy of reliable and diversified access to the broadest possible markets.

Net operating costs per barrel for the first quarter of 2018 were 29% lower than in the first quarter of 2017, while non-energy operating costs per barrel decreased 13% over the same time period. The ongoing reduction in net operating costs and non-energy operating costs in the first quarter of 2018 is primarily a result of efficiency gains and continued cost management.

Vision 20/20

"The implementation of eMSAGP and the brownfield expansion on Phase 2B are key components for achievement of MEG's Vision 20/20," said Bill McCaffrey. "Following the implementation of these two phases of growth, we will have decreased our overall cash costs by approximately $3 per barrel from current levels, improved our balance sheet metrics, and positioned the company to grow thereafter while generating free cash flow."

Capital investment during the first quarter of 2018 totalled $148 million. The majority of the capital was dedicated towards the drilling of new infills and well pairs as the implementation of eMSAGP continued on Phase 2B. The brownfield expansion on Phase 2B commenced during the quarter and is proceeding on schedule. Construction of the eMVAPEX pilot was also advanced.

"Vision 20/20, once completed, will enable MEG to enter a new chapter. From a stronger operating and financial foundation, we will be in an improved position to respond to changing market conditions," said McCaffrey. "It is with this clear vision in mind that this is the right time for me to retire. With Management and the Board fully aligned on this vision, I am confident that MEG has the internal bench strength and the technical and financial capabilities to successfully carry out this transition."

Adjusted Funds Flow and Earnings

MEG realized adjusted funds flow from operations of $83 million for the first quarter of 2018 compared to adjusted funds flow from operations of $43 million in the same quarter of 2017. This 93% increase primarily reflects increased bitumen sales volumes and a reduction in net interest expense primarily due to realized gains on the company's interest rate swap contract.

The company recorded a first quarter 2018 operating loss of $18 million compared to an operating loss of $79 million for the same period in 2017. The decrease in the operating loss was primarily the result of higher bitumen sales volumes. Bitumen sales averaged 91,608 bpd for the first quarter of 2018 compared to 74,703 bpd for the same time period in 2017.

Forward-Looking Information and Non-GAAP Financial Measures

This quarterly report contains forward-looking information and financial measures that are not defined by International Financial Reporting Standards ("IFRS") and should be read in conjunction with the "Forward-Looking Information" and "Non-GAAP Financial Measures" contained within the Advisory section of this quarter's Management's Discussion and Analysis.

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 three-month period ended March 31, 2018 was approved by the Corporation's Audit Committee on May 9, 2018. This MD&A should be read in conjunction with the Corporation's unaudited interim consolidated financial statements and notes thereto for the three-month period ended March 31, 2018, the audited annual consolidated financial statements and notes thereto for the year ended December 31, 2017, the 2017 annual MD&A and the Corporation's most recently filed Annual Information Form ("AIF"). This MD&A and the unaudited interim consolidated financial statements and comparative information have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and are presented in thousands of Canadian dollars, except where otherwise indicated.

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1. BUSINESS DESCRIPTION

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. For information regarding MEG's estimated reserves contained in the GLJ Petroleum Consultants Ltd. Report ("GLJ Report"), please refer to the Corporation's most recently filed 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.

The Corporation has identified three commercial SAGD projects: the Christina Lake Project, the Surmont Project and the May River Regional Project. The Christina Lake Project has received regulatory approval for 210,000 barrels per day ("bbls/d") of bitumen production. MEG has applied for regulatory approval for 120,000 bbls/d of bitumen production at the Surmont Project. On February 21, 2017, MEG filed regulatory applications with the Alberta Energy Regulator for the May River Regional Project. Management anticipates, consistent with the estimates contained in the GLJ Report, that the May River Regional Project can support an average of 164,000 bbls/d of bitumen production. The ultimate production rate and life of each project will be dependent on a number of factors, including the size, performance and development schedule for each expansion or phase in those projects. In addition, the Corporation holds other leases known as the "Growth Properties." The Growth Properties are in the resource definition and data gathering stage of development.

The Corporation's first two production phases at the Christina Lake Project, Phase 1 and Phase 2, commenced production in 2008 and 2009, respectively. In 2012, the Corporation announced the RISER initiative, which is a combination of proprietary reservoir technologies, including enhanced Modified Steam And Gas Push ("eMSAGP") and redeployment of steam and facilities modifications, including debottlenecking and brownfield expansions (collectively "RISER"). Phase 2B commenced production in 2013. To further enhance production, the Corporation is testing its proprietary recovery process known as enhanced Modified VAPour EXtraction ("eMVAPEX") at the Christina Lake project, which involves the targeted injection of light hydrocarbons in replacement of steam. Bitumen production at the Christina Lake Project for the year ended December 31, 2017 averaged 80,774 bbls/d. The application of eMSAGP and cogeneration have enabled MEG to lower its greenhouse gas intensity below the *in situ* industry average calculated based on reported data to Environment Canada, the Alberta Energy Regulator and the Alberta Electric System Operator. In those specific well patterns where the implementation of eMSAGP has already been deployed, the Corporation is currently experiencing a steam-oil ratio of approximately 1.3. MEG is currently continuing the process of implementing the RISER initiative, and specifically eMSAGP, to Phase 2B of the Christina Lake Project.

The Surmont Project has an anticipated design capacity of approximately 120,000 bbls/d over multiple phases. The Surmont Project is located approximately 30 miles north of the Corporation's Christina Lake Project, and is situated along the same geological trend as the Christina Lake Project. The Corporation is actively pursuing regulatory approval.

On January 27, 2017, MEG successfully completed a refinancing which extended the first maturity of any of the Corporation's outstanding long-term debt obligations to 2023.

On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. The majority of the net cash proceeds were used to repay approximately C$1.2 billion of MEG's senior secured term loan. In addition, the Corporation increased its 2018 capital budget from $510 million to $700 million to fund approximately 70% of the Corporation's 13,000 bbls/d Phase 2B brownfield expansion in 2018. As part of the transaction, MEG entered into a Transportation Services Agreement ("TSA") dedicating MEG's Christina Lake production and condensate transport to the Access Pipeline for an initial term of 30 years. The transaction also includes a Stonefell Lease Agreement which is a 30-year arrangement that secures MEG's operational control and exclusive use of 100% of the Stonefell Terminal's 900,000-barrel blend and condensate storage facility.

2. OPERATIONAL AND FINANCIAL HIGHLIGHTS

The Corporation continues to benefit from efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake project. As part of a two year development plan, the eMSAGP growth project is proceeding as planned. The implementation of eMSAGP has improved reservoir efficiency and allowed for the redeployment of steam, thereby enabling the Corporation to place additional wells into production. Bitumen production in the first quarter of 2018 averaged 93,207 bbls/d, an increase of 21% compared to the first quarter of 2017.

During the first three months of 2018, the Corporation's realized sales price decreased compared to the same period in 2017. The average US$WTI price increased 21%, however, this was more than offset by the widening WTI:WCS differential. The average WTI:WCS differential in the first three months of 2018 widened by US$9.70 per barrel to US$24.28 per barrel, or 67%, compared to the same period of 2017 due to rising production in Alberta and pipeline capacity constraints.

The Corporation's non-energy operating costs averaged $4.55 per barrel for the first three months of 2018, a 13% decrease compared to $5.20 per barrel in the same period of 2017. The decrease in per barrel costs is a result of higher production volumes, efficiency gains and continued cost management.

The Corporation realized net earnings of $140.6 million for the three months ended March 31, 2018 compared to $1.6 million for the same period of 2017. Net earnings in 2018 were affected by a $318.4 million gain on disposition of the Corporation's 50% interest in the Access Pipeline. This was partially offset by an unrealized loss on commodity risk management of $58.0 million and a net unrealized foreign exchange loss of $141.3 million.

Capital investment for the first three months of 2018 totaled $147.7 million, an increase of $70.0 million compared to the same period of 2017, primarily as a result of increased investment in the Christina Lake Phase 2B growth capital initiatives.

At March 31, 2018, the Corporation had cash and cash equivalents of $675.1 million and US$1.4 billion of undrawn capacity under the revolving credit facility.

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

	2018	2017				2016		
($ millions, except as indicated)	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Bitumen production - bbls/d	**93,207**	90,228	83,008	72,448	77,245	81,780	83,404	83,127
Bitumen realization - $/bbl	**35.31**	48.30	39.89	39.66	37.93	36.17	30.98	30.93
Net operating costs - $/bbl(1)	**5.98**	5.86	6.00	7.42	8.43	8.24	7.76	7.43
Non-energy operating costs - $/bbl	**4.55**	4.53	4.57	4.23	5.20	4.99	5.32	5.81
Cash operating netback - $/bbl(2)	**20.16**	33.83	26.84	22.96	22.33	21.73	16.74	16.09
Adjusted funds flow from operations(3)	**83**	192	83	55	43	40	23	7
Per share, diluted(3)	**0.28**	0.65	0.28	0.19	0.16	0.18	0.10	0.03
Operating earnings (loss)(3)	**(18)**	44	(43)	(36)	(79)	(72)	(88)	(98)
Per share, diluted(3)	**(0.06)**	0.15	(0.14)	(0.12)	(0.29)	(0.32)	(0.39)	(0.43)
Revenue(4)	**721**	755	546	574	560	566	497	513
Net earnings (loss)	**141**	(1)	84	104	2	(305)	(109)	(146)
Per share, basic	**0.48**	(0.00)	0.29	0.36	0.01	(1.34)	(0.48)	(0.65)
Per share, diluted	**0.47**	(0.00)	0.28	0.35	0.01	(1.34)	(0.48)	(0.65)
Total cash capital investment	**148**	163	103	158	78	63	19	20
Cash and cash equivalents	**675**	464	398	512	549	156	103	153
Long-term debt	**3,543**	4,637	4,636	4,813	4,945	5,053	4,910	4,871

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

(2) Cash operating netback is calculated by deducting the related diluent expense, blend purchases, transportation, operating expenses, royalties and realized commodity risk management gains (losses) from proprietary blend revenues and power revenues, on a per barrel of bitumen sales volume basis.

(3) Adjusted funds flow from (used in) operations, Operating earnings (loss) and the related per share amounts do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. The non-GAAP measure of adjusted funds flow from (used in) operations is reconciled to net cash provided by (used in) operating activities and the non-GAAP measure of operating earnings (loss) is reconciled to net earnings (loss) 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 and Comprehensive Income.

3. RESULTS OF OPERATIONS

Bitumen Production and Steam-Oil Ratio

	Three months ended March 31	
	2018	**2017**
Bitumen production – bbls/d	**93,207**	77,245
Steam-oil ratio (SOR)	**2.2**	2.4

Bitumen Production

Bitumen production at the Christina Lake Project averaged 93,207 bbls/d for the three months ended March 31, 2018 compared to 77,245 bbls/d for the three months ended March 31, 2017. The increase in average production volumes for the three months ended March 31, 2018 is primarily due to the efficiency gains achieved through the continued implementation of eMSAGP at the Christina Lake Project. The implementation of eMSAGP has improved reservoir efficiency and allowed for the redeployment of steam, thereby enabling the Corporation to place additional wells into production.

Steam-Oil Ratio

SOR is an important efficiency indicator that measures the average amount of steam that is injected into the reservoir for each barrel of bitumen produced. The Corporation continues to focus on maintaining efficiency of production through a lower SOR. The SOR averaged 2.2 for the three months ended March 31, 2018 compared to 2.4 for the three months ended March 31, 2017.

Operating Cash Flow

	Three months ended March 31	
($000)	**2018**	**2017**
Petroleum revenue – proprietary[1]	**$ 672,890**	$ 489,388
Blend purchases[2]	**(48,798)**	-
Diluent expense	**(332,966)**	(234,399)
	291,126	254,989
Royalties	**(8,508)**	(5,691)
Transportation expense	**(51,976)**	(46,898)
Operating expenses	**(59,230)**	(63,053)
Power revenue	**9,956**	6,356
Transportation revenue	**2,610**	2,953
	183,978	148,656
Realized gain (loss) on commodity risk management	**(17,719)**	1,512
Operating cash flow[3]	**$ 166,259**	$ 150,168

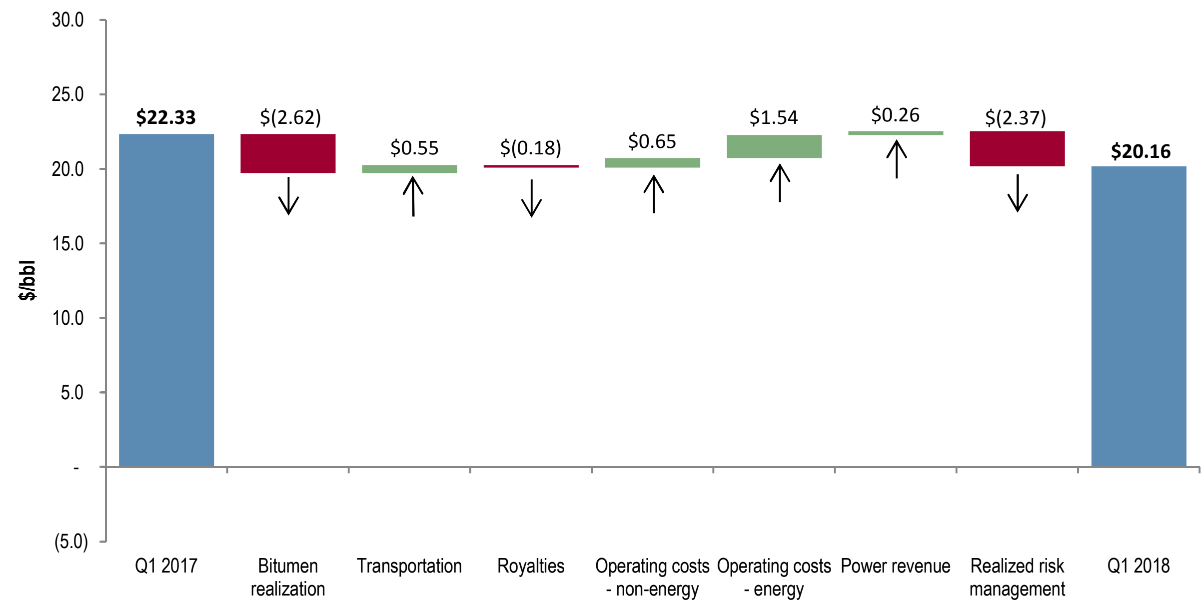
(1) *Proprietary petroleum revenue represents MEG's revenue ("blend sales revenue") from its heavy crude oil blend known as Access Western Blend ("AWB" or "blend"). Blend is comprised of bitumen produced at the Christina Lake Project blended with purchased diluent.*

(2) *Effective January 1, 2018, blend purchases are presented on a gross basis as they represent separate performance obligations, as discussed in the "NEW ACCOUNTING STANDARDS" section of this MD&A.*

(3) *A non-GAAP measure as defined in the "NON-GAAP MEASURES" section of this MD&A.*

Operating cash flow was $166.3 million for the three months ended March 31, 2018 compared to $150.2 million for the three months ended March 31, 2017. The 11% increase is primarily due to higher blend sales revenue, partially offset by an increase in diluent expense. The increase in blend sales revenue is primarily due to a 22% increase in blend sales volumes. Diluent expense for the three months ended March 31, 2018 was $98.6 million higher than the three months ended March 31, 2017, due to an increase in condensate volumes, reflecting the increase in average bitumen production, and higher condensate benchmark prices.

Cash Operating Netback



The following table summarizes the Corporation's per-unit calculation of operating cash flow, defined as cash operating netback for the periods indicated:

	Three months ended March 31	
($/bbl)	**2018**	**2017**
Bitumen realization[1]	**$ 35.31**	$ 37.93
Transportation[2]	**(5.99)**	(6.54)
Royalties	**(1.03)**	(0.85)
	28.29	30.54
Operating costs – non-energy	**(4.55)**	(5.20)
Operating costs – energy	**(2.64)**	(4.18)
Power revenue	**1.21**	0.95
Net operating costs	**(5.98)**	(8.43)
	22.31	22.11
Realized gain (loss) on commodity risk management	**(2.15)**	0.22
Cash operating netback	**$ 20.16**	$ 22.33

(1) Blend sales revenue net of diluent expense and blend purchases.

(2) Defined as transportation expense less transportation revenue. Transportation includes pipeline, rail and storage costs, net of third-party recoveries on diluent transportation arrangements.

Bitumen Realization

Bitumen realization represents the Corporation's realized proprietary petroleum revenue ("blend sales revenue"), net of blend purchases and diluent expense, expressed on a per barrel basis. Blend sales revenue 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. The cost of blending is impacted by the amount of diluent required and the Corporation's cost of purchasing and transporting diluent to the production site. A portion of diluent expense is effectively recovered in the sales price of the blended product. Diluent expense is also impacted by Canadian and U.S. benchmark pricing, the timing of diluent inventory purchases and changes in the value of the Canadian dollar relative to the U.S. dollar.

Bitumen realization averaged $35.31 per barrel for the three months ended March 31, 2018 compared to $37.93 per barrel for the three months ended March 31, 2017. The average US$WTI price increased 21% for the three months ended March 31, 2018 compared to the same period in 2017. However, this was more than offset by the widening of the WTI:WCS differential by US$9.70 per barrel and the quarter-over-quarter increase in average condensate benchmark pricing. For the three months ended March 31, 2018, the Corporation's cost of diluent was $83.91 per barrel of diluent compared to $70.80 per barrel of diluent for the three months ended March 31, 2017.

Transportation

The Corporation utilizes multiple facilities to transport and sell its blend. Sales volumes destined for the U.S. Gulf Coast or overseas require additional transportation costs, but generally obtain higher sales prices.

On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. As part of the transaction, MEG entered into a Transportation Services Agreement ("TSA") dedicating MEG's Christina Lake production and condensate transport to the Access Pipeline for an initial term of 30 years. During the three months ended March 31, 2018, incremental transportation costs of approximately $2.8 million were incurred due to the cost of the TSA for a 10-day period.

During the three months ended March 31, 2018, transportation costs averaged $5.99 per barrel compared to $6.54 per barrel for the three months ended March 31, 2017. The decrease in costs on a per barrel basis is the result of higher sales volumes.

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 cumulative 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.

The increase in royalties for the three months ended March 31, 2018, compared to the three months ended March 31, 2017 is primarily the result of higher WTI crude oil prices and higher bitumen sales volumes.

Net Operating Costs

Net operating costs are comprised of the sum of non-energy operating costs and energy operating costs, reduced by power revenue. Non-energy operating costs relate to production-related operating activities. Energy operating costs reflect 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 generated by the Corporation's cogeneration facilities at the Christina Lake Project.

Net operating costs for the three months ended March 31, 2018 averaged $5.98 per barrel compared to $8.43 per barrel for the three months ended March 31, 2017. The decrease in net operating costs is primarily the result of a per barrel decrease in both non-energy and energy operating costs.

Non-energy operating costs

Non-energy operating costs averaged $4.55 per barrel for the three months ended March 31, 2018 compared to $5.20 per barrel for the three months ended March 31, 2017. The decrease in non-energy operating costs per barrel is the result of higher sales volumes. Due to the fixed nature of a significant portion of non-energy operating costs, the per barrel costs will typically decrease as production increases.

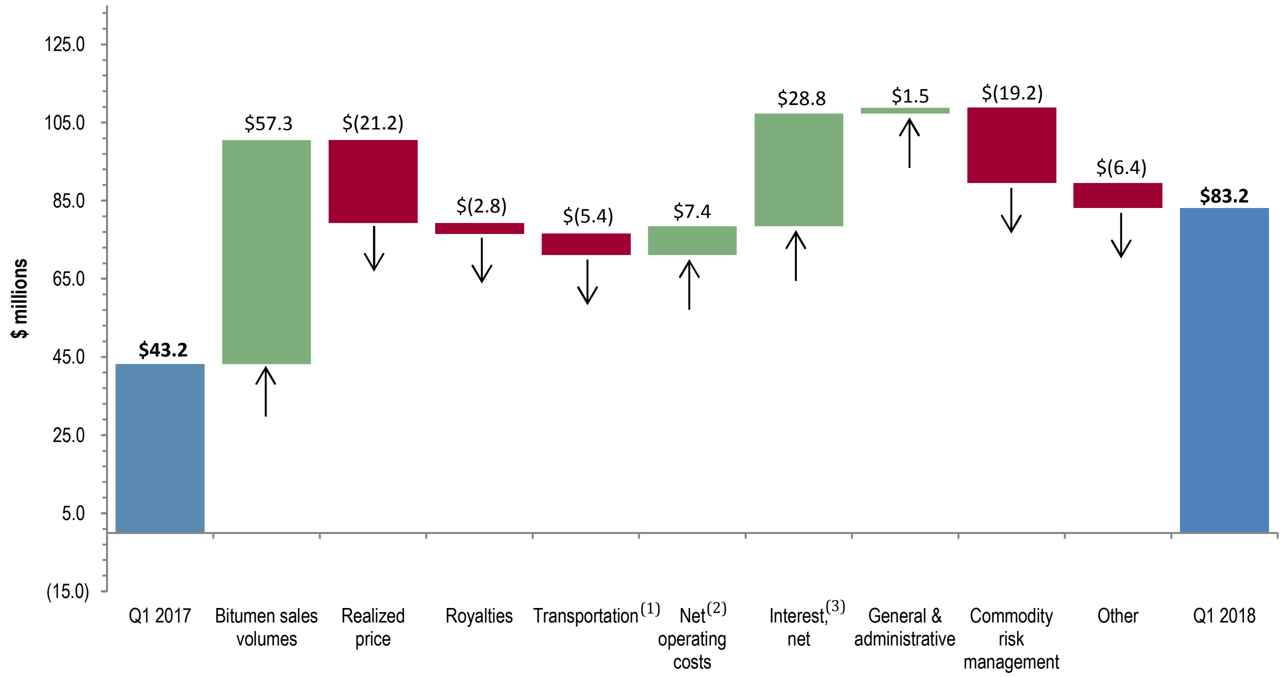
Energy operating costs

Energy operating costs averaged $2.64 per barrel for the three months ended March 31, 2018 compared to $4.18 per barrel for the three months ended March 31, 2017. The decrease in energy operating costs is primarily attributable to lower natural gas prices. The Corporation's natural gas purchase price averaged $2.40 per mcf during the three months ended March 31, 2018 compared to $3.12 per mcf for the same period in 2017.

Power revenue

Power revenue averaged $1.21 per barrel for the three months ended March 31, 2018 compared to $0.95 per barrel for the three months ended March 31, 2017. The Corporation's average realized power sales price during the three months ended March 31, 2018 was $35.50 per megawatt hour compared to $22.42 per megawatt hour for the same period in 2017.

Adjusted Funds Flow From (Used In) Operations



(1) Defined as transportation expense less transportation revenue.

(2) Includes non-energy and energy operating costs, reduced by power revenue.

(3) Defined as net interest expense plus realized gain/loss on interest rate swaps less amortization of debt discount and debt issue costs.

Adjusted funds flow from (used in) operations is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this MD&A, which is used by the Corporation to analyze operating performance and liquidity. Adjusted funds flow from operations increased by 93% in the first quarter of 2018 to $83.2 million from $43.2 million in the first quarter of 2017. The increase primarily reflects increased bitumen sales volumes and a reduction in net interest expense primarily due to a realized gain on the termination of the Corporation's US$650.0 million interest rate swap contract. These increases were partially offset by lower realized bitumen prices and realized losses on commodity risk management.

Operating Earnings (Loss)

Operating earnings (loss) is a non-GAAP measure, as defined in the "NON-GAAP MEASURES" section of this MD&A, which the Corporation uses as a performance measure to provide comparability of financial performance between periods by excluding non-operating items. The Corporation recognized an operating loss of $18.0 million for the three months ended March 31, 2018 compared to an operating loss of $79.4 million for the three months ended March 31, 2017. The decrease in the operating loss was primarily the result of higher bitumen sales volumes. Bitumen sales averaged 91,608 bbls/d for the three months ended March 31, 2018 compared to 74,703 bbls/d for the three months ended March 31, 2017.

	Three months ended March 31	
($000)	**2018**	**2017**
Net earnings (loss)	**$ 140,573**	$ 1,588
Adjustments:		
Unrealized loss (gain) on foreign exchange(1)	**141,298**	(36,707)
Unrealized loss (gain) on derivative financial liabilities(2)	**2,976**	(2,241)
Unrealized loss (gain) on commodity risk management(3)	**58,032**	(59,599)
Realized foreign exchange loss (gain) on foreign exchange derivatives(4)	**(35,362)**	-
Gain on asset dispositions(5)	**(318,398)**	-
Onerous contracts expense	**644**	2,375
Deferred tax expense (recovery) relating to these adjustments	**(7,778)**	15,230
Operating earnings (loss)(6)	**$ (18,015)**	$ (79,354)

(1) *Unrealized net foreign exchange gains and losses result from the translation of U.S. dollar denominated long-term debt and cash and cash equivalents using period-end exchange rates.*
(2) *Unrealized gains and losses on derivative financial liabilities result from the interest rate floor on the Corporation's long-term debt and interest rate swaps entered into to effectively fix a portion of its variable rate long-term debt.*
(3) *Unrealized gains or losses on commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.*
(4) *A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on those Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.*
(5) *A gain related to the sale of the Corporation's 50% interest in the Access Pipeline.*
(6) *A non-GAAP measure as defined in the "NON-GAAP MEASURES" section of this MD&A.*

Revenue

Revenue represents the total of petroleum revenue, net of royalties and other revenue. Revenue for the three months ended March 31, 2018 totaled $720.6 million compared to $559.8 million for the three months ended March 31, 2017. Revenue increased primarily due to an increase in blend sales volumes.

Net Earnings (Loss)

The Corporation recognized net earnings of $140.6 million for the three months ended March 31, 2018 compared to $1.6 million for the three months ended March 31, 2017. The net earnings for the three months ended March 31, 2018 were affected by a gain on asset dispositions of $318.4 million relating to the sale of the Corporation's 50% interest in the Access Pipeline. This was partially offset by an unrealized loss on commodity risk management of $58.0 million and a net unrealized foreign exchange loss of $141.3 million. In comparison, the net earnings in the first quarter of 2017 included an unrealized gain on commodity risk management of $59.6 million and a net unrealized foreign exchange gain of $36.7 million.

Total Cash Capital Investment

Total cash capital investment during the three months ended March 31, 2018 totaled $147.7 million as compared to $77.8 million for the three months ended March 31, 2017. Capital investment for the first three months of 2018 has been primarily directed towards the Corporation's growth capital initiatives at Christina Lake Phase 2B and sustaining capital activities.

4. OUTLOOK

Summary of 2018 Guidance	
Capital investment	$700 million
Bitumen production – annual average (bbls/d)	85,000 – 88,000
Bitumen production – targeted exit volume (bbls/d)	95,000 – 100,000
Non-energy operating costs ($/bbl)	$4.75 – $5.25

On December 1, 2017, the Corporation announced a 2018 capital budget of $510 million. On February 8, 2018, following the announcement of the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal, the Corporation announced an increase in its 2018 capital budget from $510 million to $700 million to fund approximately 70% of the Corporation's 13,000 bbls/d Phase 2B brownfield expansion in 2018. The Corporation expects to fund the 2018 capital program with internally generated cash flow, a portion of the proceeds from the asset sales and existing cash.

The Corporation's 2018 average annual bitumen production volumes are targeted to be in the range of 85,000 – 88,000 bbls/d. Exit bitumen production for 2018 is targeted to be in the range of 95,000 – 100,000 bbls/d. Non-energy operating costs are targeted to be in the range of $4.75 – $5.25 per barrel. The operational guidance takes into account a major turnaround at the Corporation's Christina Lake Phase 2B facility in the second quarter of 2018, with an anticipated 5,000 to 6,000 bbls/d impact on average production volumes for the year.

5. BUSINESS ENVIRONMENT

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

	2018	2017				2016		
	Q1	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
Average Commodity Prices								
Crude oil prices								
Brent (US$/bbl)	**67.18**	61.54	52.18	50.93	54.66	51.13	46.98	46.67
WTI (US$/bbl)	**62.87**	55.40	48.21	48.29	51.91	49.29	44.94	45.59
WTI (C$/bbl)	**79.54**	70.45	60.38	64.94	68.68	65.75	58.65	58.75
WCS (C$/bbl)	**48.82**	54.86	47.93	49.98	49.39	46.65	41.03	41.61
Differential – WTI:WCS (US$/bbl)	**24.28**	12.26	9.94	11.13	14.58	14.32	13.50	13.30
Differential – WTI:WCS (%)	**38.6%**	22.1%	20.6%	23.0%	28.1%	29.1%	30.0%	29.2%
Condensate prices								
Condensate at Edmonton (C$/bbl)	**79.72**	73.72	59.59	65.16	69.17	64.49	56.25	56.83
Condensate at Edmonton as % of WTI	**100.2%**	104.6%	98.7%	100.3%	100.7%	98.1%	95.9%	96.7%
Condensate at Mont Belvieu, Texas (US$/bbl)	**59.27**	55.35	46.37	44.77	46.05	45.17	41.17	40.37
Condensate at Mont Belvieu, Texas as % of WTI	**94.3%**	99.9%	96.2%	92.7%	88.7%	91.6%	91.6%	88.6%
Natural gas prices								
AECO (C$/mcf)	**2.26**	1.84	1.58	2.81	2.91	3.31	2.49	1.37
Electric power prices								
Alberta power pool (C$/MWh)	**34.81**	22.49	24.55	19.26	22.38	21.97	17.93	14.77
Foreign exchange rates								
C$ equivalent of 1 US$ - average	**1.2651**	1.2717	1.2524	1.3449	1.3230	1.3339	1.3051	1.2886
C$ equivalent of 1 US$ - period end	**1.2901**	1.2518	1.2510	1.2977	1.3322	1.3427	1.3117	1.3009

Crude Oil Prices

Brent crude is the primary world price benchmark for global light sweet crude oil. 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 the royalty rate on the Corporation's bitumen sales. The WTI price averaged US$62.87 per barrel for the three months ended March 31, 2018 compared to US$51.91 per barrel for the three months ended March 31, 2017.

WCS is a blend of heavy oils, consisting of heavy conventional crude oils and bitumen, blended with sweet synthetic, light crude oil or condensate. The WCS benchmark reflects North American heavy oil prices at Hardisty, Alberta. WCS typically trades at a differential below the WTI benchmark price. The WTI:WCS differential averaged US$24.28 per barrel, or 38.6% of WTI, for the three months ended March 31, 2018 compared to US$14.58 per barrel, or 28.1% of WTI, for the three months ended March 31, 2017. The WTI:WCS differential has widened as a result of increased apportionment on pipelines that has been caused by increased heavy oil production accompanied with delays in initiating expansions of export pipelines and delays affecting the ramp up of major rail carriers' capacity.

Condensate Prices

In order to facilitate pipeline transportation, MEG uses condensate sourced throughout North America as diluent for blending with the Corporation's bitumen. Condensate prices, benchmarked at Edmonton, averaged $79.72 per barrel, or 100.2% of WTI, for the three months ended March 31, 2018 compared to $69.17 per barrel, or 100.7% of WTI, for the three months ended March 31, 2017.

Condensate prices, benchmarked at Mont Belvieu, Texas, averaged US$59.27 per barrel, or 94.3% of WTI, for the three months ended March 31, 2018 compared to US$46.05 per barrel, or 88.7% of WTI, for the three months ended March 31, 2017.

Natural Gas Prices

Natural gas is a primary energy input cost for the Corporation, as it is used as fuel to generate steam for the SAGD process and to create electricity from the Corporation's cogeneration facilities. The AECO natural gas price averaged $2.26 per mcf for the three months ended March 31, 2018 compared to $2.91 per mcf for the three months ended March 31, 2017.

Electric 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 $34.81 per megawatt hour for the three months ended March 31, 2018 compared to $22.38 per megawatt hour for the three months ended March 31, 2017.

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 revenue and diluent expense, as blend sales prices and diluent expense 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 revenue and a negative impact on diluent expense and principal and interest payments. Conversely, an increase in the value of the Canadian dollar has a negative impact on blend sales revenue and a positive impact on diluent expense and principal and interest payments.

The Corporation recognizes net unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt and U.S. dollar denominated cash and cash equivalents at each reporting date. As at March 31, 2018, the Canadian dollar, at a rate of 1.2901, had decreased in value by approximately 3% against the U.S. dollar compared to its value as at December 31, 2017, when the rate was 1.2518.

6. OTHER OPERATING RESULTS

Net Marketing Activity

	Three months ended March 31	
($000)	**2018**	**2017**
Petroleum revenue – third party	**$ 43,643**	$ 66,773
Third party purchased product	**(42,429)**	(65,542)
Net marketing activity[1]	**$ 1,214**	$ 1,231

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

The Corporation has entered into marketing arrangements for rail and pipeline transportation commitments and product storage arrangements to enhance its ability to transport proprietary crude oil products to a wider range of markets in Canada, the United States and on tidewater. In the event that the Corporation is not utilizing these arrangements for proprietary purposes, the Corporation purchases and sells third-party crude oil and related products and enters into transactions to generate revenues to offset the costs of such marketing and storage arrangements.

Depletion and Depreciation

	Three months ended March 31	
($000)	**2018**	**2017**
Depletion and depreciation expense	**$ 110,899**	$ 116,879
Depletion and depreciation expense per barrel of production	**$ 13.22**	$ 16.81

Depletion and depreciation expense decreased, primarily due to a significant reduction in estimated future development costs associated with the Corporation's proved reserves. Future development costs are derived from the Corporation's independent reserve report and are a key element of the rate determination. The decrease in future development costs is primarily related to the Corporation's future growth strategy, which anticipates reduced capital requirements to produce the reserves.

Commodity Risk Management Gain (Loss)

The Corporation has entered into financial commodity risk management contracts. The Corporation has not designated any of its commodity risk management contracts as hedges for accounting purposes. All financial commodity risk management contracts have been recorded at fair value, with all changes in fair value recognized through net earnings (loss). Realized gains or losses on financial commodity risk management contracts are the result of contract settlements during the period. Unrealized gains or losses on financial commodity risk management contracts represent the change in the mark-to-market position of the unsettled commodity risk management contracts during the period.

	Three months ended March 31					
($000)	**2018**			**2017**		
	Realized	**Unrealized**	**Total**	**Realized**	**Unrealized**	**Total**
Crude oil contracts[1]	**$ (17,719)**	**$ (58,419)**	**$ (76,138)**	$ (3,894)	$ 61,690	$ 57,796
Condensate contracts[2]	**-**	**387**	**387**	5,406	(2,091)	3,315
Commodity risk management gain (loss)	**$ (17,719)**	**$ (58,032)**	**$ (75,751)**	$ 1,512	$ 59,599	$ 61,111

(1) *Includes WTI fixed price, WTI collars and WCS fixed differential contracts.*

(2) *Relates to condensate purchase contracts that effectively fix condensate prices at Mont Belvieu, Texas as a percentage of WTI.*

The Corporation realized a net loss on commodity risk management contracts of $17.7 million for the three months ended March 31, 2018, due to net settlement losses on contracts relating to crude oil sales. This compares to a realized net gain of $1.5 million for the three months ended March 31, 2017.

The Corporation recognized an unrealized loss on commodity risk management contracts of $58.0 million for the three months ended March 31, 2018, reflecting unrealized losses on crude oil contracts. Crude oil benchmark forward prices increased over the period, resulting in unrealized losses on the Corporation's WTI fixed price contracts and collars. The $58.0 million unrealized loss in the first quarter of 2018 compares to a $59.6 million unrealized gain for the same period in 2017. Refer to the "Risk Management" section of this MD&A for further details.

General and Administrative

	Three months ended March 31	
($000)	**2018**	**2017**
General and administrative expense	**$ 21,723**	$ 23,222
General and administrative expense per barrel of production	**$ 2.59**	$ 3.34

General and administrative expense decreased primarily due to workforce reductions and the Corporation's continued focus on cost management.

Stock-based Compensation

	Three months ended March 31	
($000)	**2018**	**2017**
Cash-settled expense (recovery)	**$ (291)**	$ (1,223)
Equity-settled expense	**6,129**	3,510
Stock-based compensation	**$ 5,838**	$ 2,287

The fair value of compensation associated with the granting of stock options, restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units ("DSUs") to officers, directors, employees and consultants is recognized by the Corporation as stock-based compensation expense. Fair values for equity-settled plans are determined using the Black-Scholes option pricing model.

The Corporation also grants RSUs, PSUs and DSUs under cash-settled plans. The cash-settled RSUs, PSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation's common shares at each period end. Fluctuations in the fair value are recognized within stock-based compensation expense or capitalized to property, plant and equipment during the period in which they occur.

Stock-based compensation expense for the three months ended March 31, 2018 was $5.8 million compared to $2.3 million for the three months ended March 31, 2017. The increase was primarily a result of an increase in equity-settled share based compensation expense.

Research and Development

	Three months ended March 31	
($000)	**2018**	**2017**
Research and development expense	**$ 988**	$ 940

Research and development expenditures relate to the Corporation's research of crude quality improvement and related technologies.

Foreign Exchange Gain (Loss), Net

	Three months ended March 31	
($000)	**2018**	**2017**
Unrealized foreign exchange gain (loss) on:		
Long-term debt	**$ (138,784)**	$ 39,758
Other	**(2,514)**	(3,051)
Unrealized net gain (loss) on foreign exchange	**(141,298)**	36,707
Realized gain (loss) on foreign exchange	**(2,010)**	2,313
Realized gain (loss) on foreign exchange derivatives	**35,362**	-
Foreign exchange gain (loss), net	**$ (107,946)**	$ 39,020
C$ equivalent of 1 US$		
Beginning of period	**1.2518**	1.3427
End of period	**1.2901**	1.3322

The net foreign exchange gains and losses are primarily due to the translation of the U.S. dollar denominated debt as a result of the strengthening or weakening of the Canadian dollar compared to the U.S. dollar during each period. For the three months ended March 31, 2018 the Canadian dollar weakened by 3% resulting in an unrealized foreign exchange loss on long-term debt of $138.8 million. For the three months ended March 31, 2017 the Canadian dollar strengthened by 1% resulting in an unrealized foreign exchange gain on long-term debt of $39.8 million.

On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of MEG's senior secured term loan. Upon entering into the sale agreement on February 8, 2018, the Corporation entered into forward currency contracts to manage the foreign exchange risk on the Canadian dollar denominated sale proceeds designated for U.S. dollar denominated long-term debt repayment. The Corporation settled these forward currency contracts on closing of the sale and realized a foreign exchange gain of $35.4 million.

Net Finance Expense

	Three months ended March 31	
($000)	**2018**	**2017**
Total interest expense	**$ 82,865**	$ 93,274
Total interest income	**(1,740)**	(806)
Net Interest expense	**81,125**	92,468
Accretion on provisions	**1,910**	1,856
Unrealized loss (gain) on derivative financial liabilities[1]	**2,976**	(2,241)
Realized loss (gain) on interest rate swaps	**(17,312)**	-
Net finance expense	**$ 68,699**	$ 92,083
Average effective interest rate[2]	**6.2%**	6.0%

(1) Derivative financial liabilities include the 1% interest rate floor and interest rate swaps.

(2) Defined as the weighted average interest rate applied to the U.S. dollar denominated senior secured term loan, Senior Secured Second Lien Notes, and Senior Unsecured Notes outstanding, including the impact of interest rate swaps.

Total interest expense for the three months ended March 31, 2018 was $82.9 million compared to $93.3 million for the three months ended March 31, 2017. The decrease was primarily due to the incremental interest expense incurred in 2017 as part of the comprehensive refinancing.

On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of the Corporation's senior secured term loan. As a result, the Corporation terminated its interest rate swap contract, which effectively fixed the interest rate on its senior secured term loan, and realized a gain of $17.3 million.

Income Tax Expense (Recovery)

	Three months ended March 31	
($000)	**2018**	**2017**
Current income tax expense (recovery)	**$ 116**	$ (284)
Deferred income tax expense (recovery)	**(29,774)**	10,979
Income tax expense (recovery)	**$ (29,658)**	$ 10,695

The Corporation recognizes current income taxes associated with its operations in the United States. The Corporation's Canadian operations are not currently taxable. As at March 31, 2018, the Corporation had approximately $7.4 billion of available Canadian tax pools.

The Corporation recognized a current income tax expense of $0.1 million for the three months ended March 31, 2018. The Corporation recognized a current income tax recovery of $0.3 million three months ended March 31, 2017. The 2018 expense of $0.1 million is related to the United States income tax associated with its operations in the United States. The 2017 recovery is comprised of $0.4 million related to the refundable Alberta tax credit on Scientific Research and Experimental Development expenditures, partially offset by an expense of $0.1 million related to the United States income tax associated with its operations in the United States.

The Corporation recognized a deferred income tax recovery of $29.8 million for the three months ended March 31, 2018 and a deferred income tax expense of $11.0 million for the three months ended March 31, 2017.

The Corporation's effective tax rate on earnings is impacted by permanent differences. The significant permanent differences are:

- The permanent difference due to capital gains arising on the disposition of the Access Pipeline and the Stonefell Terminal, and gains on foreign exchange derivatives. For the three months ended March 31, 2018, capital gains of $365.6 million were sheltered by capital loss carry forwards not previously recognized.

- The permanent difference due to the non-taxable portion of realized and unrealized foreign exchange gains and losses arising on the translation of the U.S. dollar denominated debt. For the three months ended March 31, 2018, the non-taxable net loss was $69.4 million compared to a non-taxable net gain of $19.9 million for the three months ended March 31, 2017.

- Non-taxable stock-based compensation expense for equity-settled plans is a permanent difference. Stock-based compensation expense for equity-settled plans for the three months ended March 31, 2018 was $6.1 million compared to $3.5 million for the three months ended March 31, 2017.

As at March 31, 2018, the Corporation has recognized a deferred income tax asset of $214.4 million on the Consolidated Balance Sheet, as estimated future taxable income is expected to be sufficient to realize the deferred income tax asset.

As at March 31, 2018, the Corporation had not recognized the tax benefit related to $332.3 million of realized and unrealized taxable foreign exchange losses.

7. NET CAPITAL INVESTMENT

	Three months ended March 31	
($000)	**2018**	**2017**
eMSAGP growth capital	**$ 46,743**	$ 32,885
eMVAPEX growth capital	**24,261**	5,917
Phase 2B brownfield expansion	**17,810**	-
Growth capital	**88,814**	38,802
Sustaining and maintenance	**52,488**	29,690
Field infrastructure, corporate and other	**6,437**	9,278
Total cash capital investment	**147,739**	77,770
Capitalized cash-settled stock-based compensation	**(125)**	86
	$ 147,614	$ 77,856

Total cash capital investment for the three months ended March 31, 2018 was $147.7 million as compared to $77.8 million for the three months ended March 31, 2017. The increase in capital investment was primarily related to growth capital initiatives, which are proceeding on schedule.

8. LIQUIDITY AND CAPITAL RESOURCES

($000)	March 31, 2018	December 31, 2017
Cash and cash equivalents	**$ 675,116**	$ 463,531
Senior secured term loan (March 31, 2018 – US$234.7 million; due 2023; December 31, 2017 – US$1.226 billion)	**302,722**	1,534,378
US$1.4 billion revolving credit facility (due 2021)	**-**	-
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**967,575**	938,850
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,032,080**	1,001,440
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,290,100**	1,251,800
Total debt[1]	**$ 3,592,477**	$ 4,726,468

(1) *The non-GAAP measure of total debt is reconciled to long-term debt in accordance with IFRS under the heading "NON-GAAP MEASURES" and discussed further in the "ADVISORY" section.*

Capital Resources

The Corporation's cash and cash equivalents balance totalled $675.1 million as at March 31, 2018 compared to $463.5 million as at December 31, 2017. As at March 31, 2018, no amount has been drawn under the Corporation's US$1.4 billion revolving credit facility.

The Corporation's letter of credit facility, guaranteed by Export Development Canada, has a limit of US$440 million. Letters of credit under this facility do not consume capacity of the revolving credit facility. As at March 31, 2018, the Corporation had US$146.6 million of unutilized capacity under this facility.

On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of C$1.52 billion and other consideration of C$90 million. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of MEG's senior secured term loan. Total debt decreased to C$3.6 billion as at March 31, 2018 from C$4.7 billion as at December 31, 2017.

The senior secured term loan, revolving credit facility, letter of credit facility and second lien notes are secured by substantially all the assets of the Corporation. All of MEG's long-term debt, the revolving credit facility and the letter of credit facility are "covenant-lite" in structure, meaning they are free of any financial maintenance covenants and are not dependent on, nor calculated from, the Corporation's crude oil reserves. The first maturity of any of the Corporation's outstanding long-term debt obligations is in 2023.

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 of this MD&A.

The objectives of the Corporation's investment guidelines for surplus cash are to ensure preservation of capital and to maintain adequate liquidity to meet the Corporation's cash flow requirements. The Corporation only places surplus cash investments with counterparties that have a short term credit rating of R-1 (high) or equivalent. 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 practices 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.

Risk Management

Commodity Price Risk Management

Fluctuations in commodity prices and market conditions can impact the Corporation's financial performance, operating results, cash flows, expansion and growth opportunities, access to funding and the cost of borrowing. Under the Corporation's strategic commodity risk management program, derivative financial instruments are employed with the intent of increasing the predictability of the Corporation's future cash flow. MEG's commodity risk management program is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes.
To mitigate the Corporation's exposure to fluctuations in crude oil prices, the Corporation periodically enters into financial commodity risk management contracts to partially manage its exposure on blend sales and condensate purchases.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales outstanding as at March 31, 2018:

As at March 31, 2018	Volumes (bbls/d)[1]	Term	Average Price (US$/bbl)[1]
Fixed Price:			
WTI Fixed Price	33,000	Apr 1, 2018 – Jun 30, 2018	$53.99
WTI Fixed Price	34,000	Jul 1, 2018 – Dec 31, 2018	$55.25
WTI:WCS Fixed Differential	47,000	Apr 1, 2018 – Jun 30, 2018	$(14.52)
WTI:WCS Fixed Differential	32,000	Jul 1, 2018 – Dec 31, 2018	$(14.68)
Collars:			
WTI Collars	39,500	Apr 1, 2018 – Jun 30, 2018	$46.65 – $54.88
WTI Collars	32,500	Jul 1, 2018 – Dec 31, 2018	$46.64 – $54.52

The Corporation had the following financial commodity risk management contracts relating to condensate purchases outstanding as at March 31, 2018:

As at March 31, 2018	Volumes (bbls/d) [1]	Term	Average % of WTI [1]
Mont Belvieu fixed % of WTI	1,000	Apr 1, 2018 – Jun 30, 2018	92.3%
Mont Belvieu fixed % of WTI	500	Jul 1, 2018 – Sep 30, 2018	93.5%

The Corporation entered into the following commodity risk management contracts relating to crude oil sales subsequent to March 31, 2018 up to the date of May 9, 2018:

Subsequent to March 31, 2018	Volumes (bbls/d)(1)	Term	Average Price (US$/bbl)(1)
Fixed Price:			
WTI:WCS Fixed Differential	1,000	Jul 1, 2018 – Dec 31, 2018	$(21.25)
Options:			
Purchased WTI Calls	13,800	May 1, 2018 – May 31, 2018	$69.70

The Corporation entered into the following financial commodity risk management contracts relating to condensate purchases subsequent to March 31, 2018 up to the date of May 9, 2018:

Subsequent to March 31, 2018	Volumes (bbls/d)(1)	Term	Average Price (US$/bbl)(1)
Mont Belvieu Fixed Price	750	Jul 1, 2018 – Dec 31, 2018	$65.70

Subsequent to March 31, 2018	Volumes (bbls/d)(1)	Term	Average % of WTI(1)
Mont Belvieu Fixed % of WTI	1,500	Jul 1, 2018 – Sept 30, 2018	93.2%

(1) *The volumes, prices and percentages in the above tables represent averages for various contracts with differing terms and prices. The average price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.*

Interest Rate Risk Management

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate at approximately 5.3% on US$650 million of its US$1.2 billion senior secured term loan. In the first quarter of 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal. A majority of the net cash proceeds were used to repay approximately C$1.2 billion of the Corporation's senior secured term loan. As a result, the Corporation terminated its interest rate swap contract and realized a gain of $17.3 million. The Corporation does not have any outstanding interest rate swap contracts as at March 31, 2018.

Cash Flow Summary

	Three months ended March 31	
($000)	**2018**	**2017**
Net cash provided by (used in):		
Operating activities	**$ 118,026**	$ 45,806
Investing activities	**1,368,002**	(63,936)
Financing activities	**(1,272,775)**	413,600
Effect of exchange rate changes on cash and cash equivalents held in foreign currency	**(1,668)**	(2,719)
Change in cash and cash equivalents	**$ 211,585**	$ 392,751

Cash Flow – Operating Activities

Net cash provided by operating activities totalled $118.0 million for the three months ended March 31, 2018 compared to $45.8 million for the three months ended March 31, 2017. This increase in cash flows is primarily due to higher blend sales revenue, primarily as a result of an increase in blend sales volumes, partially offset by an increase in diluent expense due to the increase in average diluent benchmark pricing.

Cash Flow – Investing Activities

Net cash from investing activities was $1.4 billion for the three months ended March 31, 2018 compared to net cash used in investing activities of $63.9 million for the three months ended March 31, 2017. The increase in cash flows is due to proceeds of $1.5 billion from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal, which closed on March 22, 2018.

Cash Flow – Financing Activities

Net cash used in financing activities was $1.3 billion for the three months ended March 31, 2018 compared to net cash provided by financing activities of $413.6 million for the three months ended March 31, 2017. Net cash used in financing activities consisted of a partial repayment of the Corporation's senior secured term loan from the majority of the net cash proceeds from the sale of the Corporation's 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal.

9. SHARES OUTSTANDING

As at March 31, 2018, the Corporation had the following share capital instruments outstanding or exercisable:

(000)	Units
Common shares	**294,105**
Convertible securities	
Stock options[1]	**8,801**
Equity-settled RSUs and PSUs	**6,226**

(1) *6.1 million stock options were exercisable as at March 31, 2018.*

As at May 8, 2018, the Corporation had 294.1 million common shares, 8.8 million stock options and 6.3 million equity-settled restricted share units and equity-settled performance share units outstanding, and 6.1 million stock options exercisable.

10. CONTRACTUAL OBLIGATIONS, COMMITMENTS AND CONTINGENCIES

(a) Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Corporation's obligations as at March 31, 2018. These maturities may differ significantly from the actual maturities of these obligations. In particular, debt under the senior secured credit facilities, the Senior Secured Second Lien Notes, and the Senior Unsecured Notes may be retired earlier due to mandatory repayments or redemptions.

($000)	2018	2019	2020	2021	2022	Thereafter	Total
Long-term debt(1)	$ 11,950	$ 15,933	$ 15,933	$ 15,933	$ 15,933	$ 3,516,795	$ 3,592,477
Interest on long-term debt(1)	177,321	235,619	234,692	233,767	232,841	262,314	1,376,554
Decommissioning obligation(2)	3,765	9,811	7,435	8,614	8,614	746,410	784,649
Transportation and storage(3)	210,853	300,300	323,702	428,728	438,780	6,601,475	8,303,838
Finance leases(4)	10,440	15,817	15,975	16,135	16,296	470,127	544,790
Office lease rentals	21,077	22,082	21,389	21,124	20,285	152,515	258,472
Diluent purchases(5)	381,871	369,281	20,217	20,162	20,162	16,792	828,485
Other commitments(6)	20,704	13,648	11,077	9,377	8,291	54,298	117,395
Total	**$ 837,981**	**$ 982,491**	**$ 650,420**	**$ 753,840**	**$ 761,202**	**$11,820,726**	**$15,806,660**

(1) This represents the scheduled principal repayments of the senior secured term loan, the senior secured second lien notes, the senior unsecured notes, and associated interest payments based on interest and foreign exchange rates in effect on March 31, 2018.

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

(3) This represents transportation and storage commitments from 2018 to 2048, including the Access Pipeline TSA, and various pipeline commitments which are awaiting regulatory approval and are not yet in service.

(4) This represents the future finance lease payments related to the Stonefell Lease Agreement.

(5) This represents the future commitments associated with the Corporation's diluent purchases.

(6) This represents the future commitments associated with the Corporation's capital program, and other operating and maintenance commitments.

Commitments for various transportation and storage arrangements increased $4.9 billion from December 31, 2017 primarily due to the Corporation's sale of its 50% interest in the Access Pipeline and the resulting TSA to transport blend production and condensate on the Access Pipeline for an initial term of 30 years. Long-term debt and interest on long-term debt decreased $1.5 billion from December 31, 2017 primarily due to the partial repayment of the Corporation's senior secured term loan.

(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.

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation continues to view this three year old claim, and the recent amendments, as without merit and will defend against all such claims.

11. NON-GAAP MEASURES

Certain financial measures in this MD&A including: net marketing activity, funds flow from (used in) operations, adjusted funds flow from (used in) operations, operating earnings (loss), operating cash flow and total debt 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 marketing and storage arrangements. Net marketing activity represents the Corporation’s third-party petroleum sales less the cost of third-party purchased product. Petroleum revenue – third party is disclosed in Note 13 and purchased product and storage – third party is presented in Note 15 to the Consolidated Financial Statements.

Funds Flow From (Used in) Operations and Adjusted Funds Flow From (Used In) Operations

Funds flow from (used in) operations and adjusted funds flow from (used in) operations are non-GAAP measures utilized by the Corporation to analyze operating performance and liquidity. Funds flow from (used in) operations excludes the net change in non-cash operating working capital while the IFRS measurement “net cash provided by (used in) operating activities” includes these items. Adjusted funds flow from (used in) operations excludes the net change in non-cash operating working capital, realized gain on foreign exchange derivatives not considered part of ordinary continuing operating results, payments on onerous contracts and decommissioning expenditures, while the IFRS measurement "net cash provided by (used in) operating activities" includes these items. Funds flow from (used in) operations and adjusted funds flow from (used in) operations are not intended to represent net cash provided by (used in) operating activities calculated in accordance with IFRS. Funds flow from (used in) operations and adjusted funds flow from (used in) operations are reconciled to net cash provided by (used in) operating activities in the table below.

	Three months ended March 31	
($000)	**2018**	**2017**
Net cash provided by (used in) operating activities	**$ 118,026**	$ 45,806
Net change in non-cash operating working capital items	**(8,136)**	(8,187)
Funds flow from (used in) operations	**109,890**	37,619
Adjustments:		
Realized gain on foreign exchange derivatives[1]	**(35,362)**	-
Payments on onerous contracts	**6,008**	4,134
Decommissioning expenditures	**2,621**	1,422
Adjusted funds flow from (used in) operations	**$ 83,157**	$ 43,175

(1) A gain related to the settlement of forward currency contracts to manage the foreign exchange risk on those Canadian dollar denominated proceeds related to the sale of assets designated for U.S. dollar denominated long-term debt repayment.

Operating Earnings (Loss)

Operating earnings (loss) 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 (loss) is defined as net earnings (loss) as reported, excluding unrealized foreign exchange gains and losses, unrealized gains and losses on derivative financial instruments, unrealized gains and losses on commodity risk management, realized gains and losses on foreign exchange derivatives, gain on asset dispositions, onerous contracts expense, and the respective deferred tax impact on these adjustments. Operating earnings (loss) is reconciled to "Net earnings (loss)", the nearest IFRS measure.

Operating Cash Flow

Operating cash flow is a non-GAAP measure widely used in the oil and gas industry as a supplemental measure of a company's efficiency and its ability to fund future capital investments. The Corporation's operating cash flow is calculated by deducting the related diluent expense, blend purchases, transportation, operating expenses, royalties and realized commodity risk management gains or losses from proprietary blend sales revenue and power revenue. The per-unit calculation of operating cash flow, defined as cash operating netback, is calculated by deducting the related diluent expense, blend purchases, transportation, operating expenses, royalties and realized commodity risk management gains or losses from proprietary blend revenue and power revenue, on a per barrel of bitumen sales volume basis.

Total Debt

Total debt is a non-GAAP measure which is used by the Corporation to analyze leverage and liquidity. The Corporation's total debt is defined as long-term debt as reported, the current portion of the senior secured term loan, the unamortized financial derivative liability discount, and the unamortized deferred debt discount and debt issue costs. Total debt is reconciled to long-term debt in the table below.

($000)	**March 31, 2018**	**December 31, 2017**
Long-term debt	**$ 3,542,763**	$ 4,668,267
Adjustments:		
Current portion of senior secured term loan	**15,933**	15,460
Unamortized financial derivative liability discount	**1,465**	4,242
Unamortized deferred debt discount and debt issue costs	**32,316**	38,499
Total debt	**$ 3,592,477**	$ 4,726,468

12. 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.

For a detailed discussion regarding the Corporation's critical accounting policies and estimates, please refer to the Corporations 2017 annual MD&A. Additional estimates, assumptions and judgments are detailed in the Corporation's unaudited interim consolidated financial statements.

Sale and leaseback accounting

On March 22, 2018, the Corporation sold its 100% interest in the Stonefell Terminal. Management applied judgment to determine that the sale of the Stonefell Terminal and the subsequent lease of the terminal should be accounted for as a sale and leaseback transaction that resulted in a finance lease.

Determining the measurement of a finance lease asset and obligation is a complex process that involves estimates, assumptions and judgments to determine the fair value of leased assets, and estimates on timing and amount of expected future cash flows and discount rates. Any future changes to the estimated discount rate will not impact the carrying values of the finance lease asset and obligation. The leased asset will be subject to property, plant and equipment impairment reviews and assessments at subsequent reporting periods.

13. NEW ACCOUNTING STANDARDS

The Corporation has adopted the following revised standards effective January 1, 2018:

IFRS 15 Revenue From Contracts With Customers

The IASB issued IFRS 15 Revenue From Contracts With Customers, which is effective January 1, 2018 and replaces IAS 11 Construction Contracts and IAS 18 Revenue and the related interpretations on revenue recognition. IFRS 15 provides a comprehensive revenue recognition and measurement framework that applies to all contracts with customers. The Corporation adopted IFRS 15 retrospectively as required by the standard on January 1, 2018, and applied a practical expedient whereby completed contracts prior to January 1, 2017 were not assessed. The adoption of this standard did not have a material impact on the Corporation's consolidated financial statements. The main changes are explained below.

(a) Significant Accounting Policies

Revenues

The Corporation earns revenue primarily from the sale of crude oil, with other revenue earned from excess power generation, and from transportation fees charged to third parties.

i. Petroleum revenue recognition

The Corporation sells proprietary and purchased crude oil and natural gas under contracts of varying terms of up to one year to customers at prevailing market prices, whereby delivery takes place throughout the contract period. In most cases, consideration is due when title has transferred and is generally collected in the month following the month of delivery.

The Corporation evaluates its arrangements with third parties to determine if the Corporation acts as the principal or as an agent. In making this evaluation, management considers if the Corporation obtains control of the product delivered. If the Corporation acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Corporation from the transaction.

Revenues associated with the sales of proprietary and purchased crude oil owned by the Corporation are recognized at a point in time when control of goods have transferred, which is generally when title passes from the Corporation to the customer. Revenues are recorded net of crown royalties, which are recognized at the time of production.

Revenue is allocated to each performance obligation on the basis of its standalone selling price and measured at the transaction price, which is the fair value of the consideration and represents amounts receivable for goods or services provided in the normal course of business. The price is allocated to each unit in the series as each unit is substantially the same and depicts the same pattern of transfer to the customer.

ii. Other revenue recognition

Revenue from power generated in excess of the Corporation's internal requirements is recognized upon delivery from the plant gate, at which point, control is transferred to the customer on the power grid. Revenues are earned at prevailing market prices for each megawatt hour produced.

Fees charged to customers for the use of pipelines and facilities owned by the Corporation are recognized in the period when the products are delivered and the services are provided.

iii. Asset dispositions

Property, plant and equipment assets are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from derecognition of the asset is determined as the difference between the net disposal proceeds, if any, and the carrying amount of the asset, and is recognized in net earnings or loss, unless the disposition is part of a sale and leaseback. The amount of consideration to be included in the gain or loss arising from derecognition is determined by the transaction contract.

Dispositions of property, plant and equipment occur on the date the acquiror obtains control of the asset.

(b) Impact from change in accounting policy

Under IFRS 15, revenues from the purchase and sale of proprietary crude oil are recognized on a gross basis as separate performance obligations. In conjunction with the transition to IFRS 15, the presentation of petroleum revenue, net of royalties and purchased product and storage will change, with no impact on earnings (loss) before income tax, net earnings (loss), comprehensive income (loss), or net cash provided by (used in) operating activities.

The quarterly impact of these changes in 2017 was as follows:

	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Total
Petroleum revenue – proprietary, as previously reported	$ 489,388	$ 492,613	$ 475,784	$ 710,817	$ 2,168,602
Blend purchases	-	9,602	30,367	6	39,975
Adjusted petroleum revenue – proprietary	**$ 489,388**	**$ 502,215**	**$ 506,151**	**$ 710,823**	**$ 2,208,577**
Purchased product and storage as previously reported	$ 65,542	$ 79,642	$ 64,738	$ 40,759	$ 250,681
Blend purchases	-	9,602	30,367	6	39,975
Adjusted purchased product and storage	**$ 65,542**	**$ 89,244**	**$ 95,105**	**$ 40,765**	**$ 290,656**

Enhanced required disclosures are provided in Notes 13 and 15 of the Corporation's consolidated financial statements.

IFRS 9 Financial Instruments

The IASB issued IFRS 9 Financial Instruments, which is effective January 1, 2018 and replaces IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 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. The accounting treatment of financial liabilities in IFRS 9 is essentially unchanged from IAS 39, except for financial liabilities designated at fair value through profit or loss, whereby an entity can recognize the portion of the change in fair value related to the change in the entity's own credit risk through other comprehensive income rather than net earnings. The standard also introduces a new expected credit loss impairment model for financial assets. In addition, IFRS 9 incorporates new hedge accounting requirements that more closely aligns with risk management activities. An amendment to IFRS 9 requires debt modifications to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate as was required under IAS 39. The adoption of this standard did not have a material impact on the Corporation's consolidated financial statements.

(a) Significant Accounting Policies

Financial Instruments

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. A financial asset or liability is measured initially at fair value plus, for an item not measured at Fair Value Through Profit or Loss ("FVTPL"), transaction costs that are directly attributable to its acquisition or issuance.

Derivative financial instruments are recognized 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 recognized in net earnings (loss) in the period in which they arise.

Financial assets and liabilities at FVTPL are classified as current except where an unconditional right to defer payment beyond 12 months exists. Derivative financial instruments are included on the balance sheet as either an asset or liability and are classified as current or non-current based on the contractual terms specific to the instrument.

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.

Derivative financial instruments are included in FVTPL unless they are designated for hedge accounting. The Corporation may periodically use derivative financial instruments to manage commodity price, foreign currency and interest rate exposures. The Corporation's commodity risk management contracts and interest rate swap contract have been classified as FVTPL.

i. Financial assets

At initial recognition, a financial asset is classified as measured at: amortized cost, FVTPL or Fair Value Through OCI ("FVTOCI") depending on the business model and contractual cash flows 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. A substantial modification to the terms of an existing financial asset results in the derecognition of the financial asset and the recognition of a new financial asset at fair value. In the event that the modification to the terms of an existing financial asset do not result in a substantial difference in the contractual cash flows the gross carrying amount of the financial asset is recalculated and the difference resulting from the adjustment in the gross carrying amount is recognized in earnings or loss.

ii. Financial liabilities

Financial liabilities are measured at amortized cost or FVTPL. 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 derecognized when the liability is extinguished. A substantial modification of the terms of an existing financial liability is recorded as an extinguishment of the original financial liability and the recognition of a new financial liability. The difference between the carrying amount of a financial liability extinguished and the consideration paid is recognized in earnings or loss. If the modification is not treated as an extinguishment, any costs or fees incurred to third parties adjust the carrying amount of the liability and are amortized over the remaining term of the modified liability at the original effective interest rate. Payments that represent compensation for the change in cash flows of a liability are expensed as part of the gain or loss on modification.

iii. Impairments

Financial Assets

Loss allowances are measured at an amount equal to the lifetime expected credit losses on the asset. Expected credit losses are a probability-weighted estimate of credit losses and are measured as the present value of all cash shortfalls for financial assets that are not credit-impaired at the reporting date and as the difference between the gross carrying amount and the present value of estimated future cash flows for financial assets that are credit-impaired at the reporting date. Loss allowances for expected credit losses for financial assets measured at amortized cost are presented in the statement of financial position as a deduction from the gross carrying amount of the asset.

(b) Impact from change in accounting policy

The classification of certain financial instruments was impacted by the adoption of IFRS 9. Trade receivables and other are measured at amortized cost under IFRS 9 as the Corporation holds the receivables with the sole intention of collecting contractual cash flows. There were no significant changes to the closing impairment allowance for financial assets determined in accordance with IAS 39 and the expected credit loss allowance determined in accordance with IFRS 9 as at January 1, 2018.

The amendment to IFRS 9 that requires debt modification to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate, as was required under IAS 39, required the Corporation to revise the opening deficit as follows:

		As at January 1, 2018
Increase to net finance expense[(i)]	$	6,381
Tax effect		(1,722)
Increase to opening deficit	**$**	**4,659**

(i) The increase to net finance expense was the result of a decrease in the unamortized financial derivative liability discount and debt issue costs which resulted in an increase in the carrying value of long-term debt as at January 1, 2018.

IFRS 2 Share-based Payment

The IASB issued amendments to IFRS 2 Share-based Payment, effective January 1, 2018 relating to classification and measurement of particular share-based payment transactions. The adoption of this revision did not have a material impact on the Corporation's consolidated financial statements.

Accounting standards issued but not yet applied

In January 2016, the IASB issued IFRS 16 Leases, which will replace IAS 17 Leases. Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. The standard eliminates the classification of leases as either operating leases or finance leases for lessees, essentially treating all leases as finance leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases. The accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, but disclosure requirements are enhanced. The standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. IFRS 16 will be adopted by the Corporation on January 1, 2019. The Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements. The Corporation anticipates there will be a material impact on the consolidated financial statements and additional new disclosures.

14. 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 construction risks, operations risks, project development risks and political-economic risks. Further information regarding the risk factors which may affect the Corporation is contained in the most recently filed Annual Information Form, which is available on the Corporation's website at www.megenergy.com and is also available on the SEDAR website at www.sedar.com.

15. 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.

16. 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.

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.

17. ABBREVIATIONS

The following provides a summary of common abbreviations used in this document:

Financial and Business Environment

AECO	Alberta natural gas price reference location
AIF	Annual Information Form
AWB	Access Western Blend
$ or C$	Canadian dollars
DSU	Deferred share units
EDC	Export Development Canada
eMSAGP	enhanced Modified Steam And Gas Push
eMVAPEX	enhanced Modified VAPour EXtraction
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
MD&A	Management's Discussion and Analysis
PSU	Performance share units
RSU	Restricted share units
SAGD	Steam-Assisted Gravity Drainage
SOR	Steam-oil ratio
U.S.	United States
US$	United States dollars
WCS	Western Canadian Select
WTI	West Texas Intermediate

Measurement

bbl	barrel
bbls/d	barrels per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
MW	megawatts
MW/h	megawatts per hour

18. 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, pricing differentials, reliability, profitability and capital investments; estimates of reserves and resources; anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and 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, competitive advantage, plans for and results of drilling activity, environmental matters, and 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, results securing access to markets and transportation infrastructure; availability of capacity on the electricity transmission grid; uncertainty of reserve and resource estimates; uncertainty associated with 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, interest rates and foreign exchange rates, and, risks and uncertainties related to commodity price, interest rate and foreign exchange rate swap contracts and/or derivative financial instruments that MEG may enter into from time to time to manage its risk related to such prices and 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; the operational risks and delays in the development, exploration, production, and the capacities and performance associated with MEG's projects; and uncertainties arising in connection with any future disposition of assets.

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 most recently filed Annual Information Form ("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 MEG assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

MEG Energy Corp. is 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 SAGD extraction methods. MEG's common shares are listed on the Toronto Stock Exchange under the symbol "MEG."

Estimates of Reserves

For information regarding MEG's estimated reserves, please refer to MEG's 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, funds flow from (used in) operations, adjusted funds flow from (used in) operations, operating earnings (loss), operating cash flow and total debt. 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 MEG'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.

19. 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.

20. QUARTERLY SUMMARIES

	2018	2017				2016		
Unaudited	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**
FINANCIAL ($000 unless specified)								
Net earnings (loss)	**140,573**	(23,779)	83,885	104,282	1,588	(304,758)	(108,632)	(146,165)
Per share, diluted	**0.47**	(0.08)	0.28	0.35	0.01	(1.34)	(0.48)	(0.65)
Operating earnings (loss)	**(18,015)**	44,055	(42,571)	(35,656)	(79,354)	(71,989)	(87,929)	(97,894)
Per share, diluted	**(0.06)**	0.15	(0.14)	(0.12)	(0.29)	(0.32)	(0.39)	(0.43)
Adjusted funds flow from operations	**83,157**	192,178	83,352	55,095	43,175	39,967	22,702	6,964
Per share, diluted	**0.28**	0.65	0.28	0.19	0.16	0.18	0.10	0.03
Cash capital investment	**147,739**	163,337	103,173	158,474	77,770	63,077	19,203	19,990
Cash and cash equivalents	**675,116**	463,531	397,598	512,424	548,981	156,230	103,136	152,711
Working capital	**445,792**	313,025	350,067	445,463	537,427	96,442	163,038	128,586
Long-term debt	**3,542,763**	4,668,267	4,635,740	4,813,092	4,944,741	5,053,239	4,909,711	4,871,182
Shareholders' equity	**4,112,531**	3,964,113	3,981,750	3,898,054	3,792,818	3,286,776	3,577,557	3,679,372
BUSINESS ENVIRONMENT								
WTI (US$/bbl)	**62.87**	55.40	48.21	48.29	51.91	49.29	44.94	45.59
C$ equivalent of 1US$ - average	**1.2651**	1.2717	1.2524	1.3449	1.3230	1.3339	1.3051	1.2886
Differential – WTI:WCS (C$/bbl)	**30.72**	15.59	12.45	14.97	19.29	19.10	17.62	17.14
Differential – WTI:WCS (%)	**38.6%**	22.1%	20.6%	23.0%	28.1%	29.1%	30.0%	29.2%
Natural gas – AECO ($/mcf)	**2.26**	1.84	1.58	2.81	2.91	3.31	2.49	1.37
OPERATIONAL ($/bbl unless specified)								
Bitumen production – bbls/d	**93,207**	90,228	83,008	72,448	77,245	81,780	83,404	83,127
Bitumen sales – bbls/d	**91,608**	94,541	76,813	74,116	74,703	81,746	84,817	80,548
Steam-oil ratio (SOR)	**2.2**	2.2	2.3	2.3	2.4	2.3	2.2	2.3
Bitumen realization	**35.31**	48.30	39.89	39.66	37.93	36.17	30.98	30.93
Transportation – net	**(5.99)**	(7.00)	(7.08)	(6.91)	(6.54)	(6.05)	(6.46)	(6.66)
Royalties	**(1.03)**	(0.84)	(0.53)	(0.87)	(0.85)	(0.51)	(0.42)	(0.27)
Operating costs – non-energy	**(4.55)**	(4.53)	(4.57)	(4.23)	(5.20)	(4.99)	(5.32)	(5.81)
Operating costs – energy	**(2.64)**	(2.03)	(2.26)	(3.76)	(4.18)	(4.12)	(2.99)	(1.97)
Power revenue	**1.21**	0.70	0.83	0.57	0.95	0.87	0.55	0.35
Realized gain (loss) on commodity risk management	**(2.15)**	(0.77)	0.56	(1.50)	0.22	0.36	0.40	(0.48)
Cash operating netback	**20.16**	33.83	26.84	22.96	22.33	21.73	16.74	16.09
Power sales price (C$/MWh)	**35.50**	21.37	23.29	18.27	22.42	21.94	17.62	13.54
Power sales (MW/h)	**130**	129	115	97	131	134	110	86
Depletion and depreciation rate per bbl of production	**13.22**	14.26	16.86	16.93	16.81	16.81	16.81	16.84
COMMON SHARES								
Shares outstanding, end of period (000)	**294,105**	294,104	294,079	294,047	293,282	226,467	226,415	226,357
Volume traded (000)	**89,721**	76,531	70,216	98,795	123,445	114,776	112,720	157,056
Common share price ($)								
High	**6.43**	6.82	5.79	7.27	9.83	9.79	6.90	7.86
Low	**4.28**	4.54	3.28	3.63	5.84	5.11	4.72	5.21
Close (end of period)	**4.55**	5.14	5.49	3.81	6.74	9.23	5.93	6.84

Interim Consolidated Financial Statements

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

As at	Note	March 31, 2018	December 31, 2017
Assets			
Current assets			
Cash and cash equivalents	19	**$ 675,116**	$ 463,531
Trade receivables and other		**300,158**	289,104
Inventories		**104,679**	85,850
		1,079,953	838,485
Non-current assets			
Property, plant and equipment	5	**6,513,012**	7,634,399
Exploration and evaluation assets	6	**548,561**	548,828
Intangible assets	7	**12,165**	13,037
Other assets	8	**207,101**	145,732
Deferred income tax asset	18	**214,373**	182,871
Total assets		**$ 8,575,165**	$ 9,363,352
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**$ 463,891**	$ 413,905
Current portion of long-term debt	9	**15,933**	15,460
Current portion of provisions and other liabilities	10	**27,656**	27,446
Commodity risk management	21	**126,681**	68,649
		634,161	525,460
Non-current liabilities			
Long-term debt	9	**3,542,763**	4,668,267
Provisions and other liabilities	10	**285,710**	205,512
Total liabilities		**4,462,634**	5,399,239
Shareholders' equity			
Share capital	11	**5,403,978**	5,403,978
Contributed surplus		**173,439**	166,636
Deficit		**(1,493,177)**	(1,629,091)
Accumulated other comprehensive income		**28,291**	22,590
Total shareholders' equity		**4,112,531**	3,964,113
Total liabilities and shareholders' equity		**$ 8,575,165**	$ 9,363,352

Commitments and contingencies (Note 23)

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

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

		Three months ended March 31	
	Note	**2018**	**2017** Revised (Note 3)
Revenues			
Petroleum revenue, net of royalties	3,13	**$ 708,025**	$ 550,470
Other revenue	3,13	**12,566**	9,309
		720,591	559,779
Expenses			
Diluent and transportation	14	**384,942**	281,297
Operating expenses		**59,230**	63,053
Purchased product and storage	3,15	**91,227**	65,542
Depletion and depreciation	5,7	**110,899**	116,879
General and administrative		**21,723**	23,222
Stock-based compensation	12	**5,838**	2,287
Research and development		**988**	940
Net finance expense	17	**68,699**	92,083
Other expenses		**831**	2,324
Gain on asset dispositions	5	**(318,398)**	-
Commodity risk management loss (gain)	21	**75,751**	(61,111)
Foreign exchange loss (gain), net	16	**107,946**	(39,020)
Earnings before income taxes		**110,915**	12,283
Income tax expense (recovery)	18	**(29,658)**	10,695
Net earnings		**140,573**	1,588
Other comprehensive income (loss), net of tax			
Items that may be reclassified to profit or loss:			
Foreign currency translation adjustment		**5,701**	(1,457)
Comprehensive income for the period		**$ 146,274**	$ 131
Net earnings per common share			
Basic	20	**$ 0.48**	$ 0.01
Diluted	20	**$ 0.47**	$ 0.01

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

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

	Note	Share Capital	Contributed Surplus	Deficit	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance as at December 31, 2017		**$ 5,403,978**	**$ 166,636**	**$ (1,629,091)**	**$ 22,590**	**$ 3,964,113**
IFRS 9 opening deficit adjustment	3	**-**	**-**	**(4,659)**	**-**	**(4,659)**
Stock-based compensation		**-**	**6,803**	**-**	**-**	**6,803**
Comprehensive income		**-**	**-**	**140,573**	**5,701**	**146,274**
Balance as at March 31, 2018		**$ 5,403,978**	**$ 173,439**	**$ (1,493,177)**	**$ 28,291**	**$ 4,112,531**
Balance as at December 31, 2016		$ 4,878,607	$ 168,253	$ (1,795,067)	$ 34,983	$ 3,286,776
Shares issued	11	517,816	-	-	-	517,816
Share issue costs, net of tax	11	(15,698)	-	-	-	(15,698)
Stock-based compensation		-	3,793	-	-	3,793
Comprehensive income (loss)		-	-	1,588	(1,457)	131
Balance as at March 31, 2017		$ 5,380,725	$ 172,046	$ (1,793,479)	$ 33,526	$ 3,792,818

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

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

		Three months ended March 31	
	Note	**2018**	**2017**
Cash provided by (used in):			
Operating activities			
Net earnings		**$ 140,573**	$ 1,588
Adjustments for:			
Depletion and depreciation	5,7	**110,899**	116,879
Stock-based compensation	12	**6,129**	3,510
Unrealized loss (gain) on foreign exchange	16	**141,298**	(36,707)
Unrealized loss (gain) on derivative financial liabilities	17	**2,976**	(2,241)
Unrealized loss (gain) on risk management	21	**58,032**	(59,599)
Onerous contracts expense		**644**	2,375
Deferred income tax expense (recovery)	18	**(29,774)**	10,979
Amortization of debt discount and debt issue costs	8,9	**4,728**	5,026
Gain on asset dispositions	5	**(318,398)**	-
Other		**1,412**	1,365
Decommissioning expenditures	10	**(2,621)**	(1,422)
Payments on onerous contracts	10	**(6,008)**	(4,134)
Net change in non-cash working capital items	19	**8,136**	8,187
Net cash provided by (used in) operating activities		**118,026**	45,806
Investing activities			
Capital investments:			
Property, plant and equipment	5	**(147,254)**	(77,641)
Exploration and evaluation	6	**(438)**	(213)
Intangible assets	7	**78**	(2)
Net proceeds on dispositions	5	**1,502,869**	-
Deferred lease inducements and other	10	**(657)**	10,635
Net change in non-cash working capital items	19	**13,404**	3,285
Net cash provided by (used in) investing activities		**1,368,002**	(63,936)
Financing activities			
Issue of shares, net of issue costs	11	**-**	496,312
Redemption of senior unsecured notes		**-**	(1,008,825)
Issue of senior secured second lien notes		**-**	1,008,825
Payments on term loan	19	**(1,272,775)**	(655)
Refinancing costs		**-**	(82,057)
Net cash provided by (used in) financing activities		**(1,272,775)**	413,600
Effect of exchange rate changes on cash and cash equivalents held in foreign currency		**(1,668)**	(2,719)
Change in cash and cash equivalents		**211,585**	392,751
Cash and cash equivalents, beginning of period		**463,531**	156,230
Cash and cash equivalents, end of period		**$ 675,116**	$ 548,981

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

1. CORPORATE INFORMATION

MEG Energy Corp. (the "Corporation") was incorporated under the *Alberta Business Corporations Act* on March 9, 1999. The Corporation's shares trade on the Toronto Stock Exchange ("TSX") under the symbol "MEG". The Corporation owns a 100% interest in over 900 square miles of oil sands leases in the southern 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 Project.

On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for cash proceeds of $1.52 billion and other consideration of $90 million (Note 5).

The corporate office is located at 600 – 3rd Avenue SW, Calgary, Alberta, Canada.

2. BASIS OF PRESENTATION

The unaudited interim consolidated financial statements ("interim consolidated financial statements") were prepared using the same accounting policies and methods as those used in the Corporation's audited consolidated financial statements for the year ended December 31, 2017, except as described in Note 3. The interim consolidated financial statements are in compliance with International Accounting Standard 34, Interim Financial Reporting ("IAS 34"). Accordingly, certain information and footnote disclosure normally included in annual financial statements prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"), has been omitted or condensed. The preparation of interim consolidated financial statements in accordance with IAS 34 requires the use of certain critical accounting estimates. It also requires management to exercise judgment in applying the Corporation's accounting policies. The areas involving a higher degree of judgment or complexity, or areas where assumptions and estimates are significant to the consolidated financial statements, have been set out in Note 4 of the Corporation's audited consolidated financial statements for the year ended December 31, 2017. These interim consolidated financial statements should be read in conjunction with the Corporation's audited consolidated financial statements for the year ended December 31, 2017.

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

These interim consolidated financial statements were approved by the Corporation's Audit Committee on May 9, 2018.

3. CHANGE IN ACCOUNTING POLICIES

New accounting standards

(a) IFRS 15 *Revenue From Contracts With Customers*

The IASB issued IFRS 15 *Revenue From Contracts With Customers*, which is effective January 1, 2018 and replaces IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. IFRS 15 provides a comprehensive revenue recognition and measurement framework that applies to all contracts with customers. The Corporation adopted IFRS 15 retrospectively as required by the standard on January 1, 2018, and applied a practical expedient whereby completed contracts prior to January 1, 2017 were not assessed. The adoption of this standard did not have a material impact on the Corporation's consolidated financial statements. The main changes are explained below.

i. Significant Accounting Policies

Revenues

The Corporation earns revenue primarily from the sale of crude oil, with other revenue earned from excess power generation, and from transportation fees charged to third parties.

(1) Petroleum revenue recognition

The Corporation sells proprietary and purchased crude oil and natural gas under contracts of varying terms of up to one year to customers at prevailing market prices, whereby delivery takes place throughout the contract period. In most cases, consideration is due when title has transferred and is generally collected in the month following the month of delivery.

The Corporation evaluates its arrangements with third parties to determine if the Corporation acts as the principal or as an agent. In making this evaluation, management considers if the Corporation obtains control of the product delivered. If the Corporation acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net-basis, only reflecting the fee, if any, realized by the Corporation from the transaction.

Revenues associated with the sales of proprietary and purchased crude oil owned by the Corporation are recognized at a point in time when control of goods have transferred, which is generally when title passes from the Corporation to the customer. Revenues are recorded net of crown royalties, which are recognized at the time of production.

Revenue is allocated to each performance obligation on the basis of its standalone selling price and measured at the transaction price, which is the fair value of the consideration and represents amounts receivable for goods or services provided in the normal course of business. The price is allocated to each unit in the series as each unit is substantially the same and depicts the same pattern of transfer to the customer.

(2) Other revenue recognition

Revenue from power generated in excess of the Corporation's internal requirements is recognized upon delivery from the plant gate, at which point, control is transferred to the customer on the power grid. Revenues are earned at prevailing market prices for each megawatt hour produced.

Fees charged to customers for the use of pipelines and facilities owned by the Corporation are recognized in the period when the products are delivered and the services are provided.

(3) Asset dispositions

Property, plant and equipment assets are derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising from derecognition of the asset is determined as the difference between the net disposal proceeds, if any, and the carrying amount of the asset, and is recognized in net earnings or loss, unless the disposition is part of a sale and leaseback. The amount of consideration to be included in the gain or loss arising from derecognition is determined by the transaction contract.

Dispositions of property, plant and equipment occur on the date the acquiror obtains control of the asset.

ii. Impact from change in accounting policy

Under IFRS 15, revenues from the purchase and sale of proprietary crude oil are recognized on a gross basis as separate performance obligations. In conjunction with the transition to IFRS 15, the presentation of petroleum revenue, net of royalties and purchased product and storage will change, with no impact on earnings (loss) before income tax, net earnings (loss), comprehensive income (loss), or net cash provided by (used in) operating activities.

The quarterly impact of these changes in 2017 was as follows:

	Q1 2017	Q2 2017	Q3 2017	Q4 2017	Total
Petroleum revenue – proprietary, as previously reported	$ 489,388	$ 492,613	$ 475,784	$ 710,817	$2,168,602
Blend purchases	-	9,602	30,367	6	39,975
Adjusted petroleum revenue – proprietary	**$ 489,388**	**$ 502,215**	**$ 506,151**	**$ 710,823**	**$2,208,577**
Purchased product and storage as previously reported	$ 65,542	$ 79,642	$ 64,738	$ 40,759	$ 250,681
Blend purchases	-	9,602	30,367	6	39,975
Adjusted purchased product and storage	**$ 65,542**	**$ 89,244**	**$ 95,105**	**$ 40,765**	**$ 290,656**

Enhanced required disclosures are provided in Notes 13 and 15.

(b) IFRS 9 *Financial Instruments*

The IASB issued IFRS 9 *Financial Instruments*, which is effective January 1, 2018 and replaces IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 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. The accounting treatment of financial liabilities in IFRS 9 is essentially unchanged from IAS 39, except for financial liabilities designated at fair value through profit or loss, whereby an entity can recognize the portion of the change in fair value related to the change in the entity's own credit risk through other comprehensive income rather than net earnings. The standard also introduces a new expected credit loss impairment model for financial assets. In addition, IFRS 9 incorporates new hedge accounting requirements that more closely aligns with risk management activities. An amendment to IFRS 9 requires debt modifications to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate as was required under IAS 39. The adoption of this standard did not have a material impact on the Corporation's consolidated financial statements.

i. Significant Accounting Policies

Financial Instruments

Financial assets and liabilities are recognized when the Corporation becomes a party to the contractual provisions of the instrument. A financial asset or liability is measured initially at fair value plus, for an item not measured at Fair Value Through Profit or Loss ("FVTPL"), transaction costs that are directly attributable to its acquisition or issuance.

Derivative financial instruments are recognized 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 recognized in net earnings (loss) in the period in which they arise.

Financial assets and liabilities at FVTPL are classified as current except where an unconditional right to defer payment beyond 12 months exists. Derivative financial instruments are included on the balance sheet as either an asset or liability and are classified as current or non-current based on the contractual terms specific to the instrument.

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.

Derivative financial instruments are included in FVTPL unless they are designated for hedge accounting. The Corporation may periodically use derivative financial instruments to manage commodity price, foreign currency and interest rate exposures. The Corporation's commodity risk management contracts and interest rate swap contract have been classified as FVTPL.

Financial Assets

At initial recognition, a financial asset is classified as measured at: amortized cost, FVTPL or Fair Value Through OCI ("FVTOCI") depending on the business model and contractual cash flows 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. A substantial modification to the terms of an existing financial asset results in the derecognition of the financial asset and the recognition of a new financial asset at fair value. In the event that the modification to the terms of an existing financial asset do not result in a substantial difference in the contractual cash flows the gross carrying amount of the financial asset is recalculated and the difference resulting from the adjustment in the gross carrying amount is recognized in earnings or loss.

Financial Liabilities

Financial liabilities are measured at amortized cost or FVTPL. 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 derecognized when the liability is extinguished. A substantial modification of the terms of an existing financial liability is recorded as an extinguishment of the original financial liability and the recognition of a new financial liability. The difference between the carrying amount of a financial liability extinguished and the consideration paid is recognized in earnings or loss. If the modification is not treated as an extinguishment, any costs or fees incurred to third parties adjust the carrying amount of the liability and are amortized over the remaining term of the modified liability at the original effective interest rate. Payments that represent compensation for the change in cash flows of a liability are expensed as part of the gain or loss on modification.

Impairments

Financial assets

Loss allowances are measured at an amount equal to the lifetime expected credit losses on the asset. Expected credit losses are a probability-weighted estimate of credit losses and are measured as the present value of all cash shortfalls for financial assets that are not credit-impaired at the reporting date and as the difference between the gross carrying amount and the present value of estimated future cash flows for financial assets that are credit-impaired at the reporting date. Loss allowances for expected credit losses for financial assets measured at amortized cost are presented in the statement of financial position as a deduction from the gross carrying amount of the asset.

ii. Impact from change in accounting policy

The classification of certain financial instruments was impacted by the adoption of IFRS 9. Trade receivables and other are measured at amortized cost under IFRS 9 as the Corporation holds the receivables with the sole intention of collecting contractual cash flows. There were no significant changes to the closing impairment allowance for financial assets determined in accordance with IAS 39 and the expected credit loss allowance determined in accordance with IFRS 9 as at January 1, 2018.

The amendment to IFRS 9 that requires debt modification to be discounted at the original effective interest rate of the debt rather than a revised effective interest rate, as was required under IAS 39, required the Corporation to revise the opening deficit as follows:

		As at January 1, 2018
Increase to net finance expense[(i)]	$	6,381
Tax effect		(1,722)
Increase to opening deficit	**$**	**4,659**

(i) The increase to net finance expense was the result of a decrease in the unamortized financial derivative liability discount and debt issue costs which resulted in an increase in the carrying value of long-term debt as at January 1, 2018.

(c) IFRS 2 *Share-based Payment*

The IASB issued amendments to IFRS 2 *Share-based Payment*, effective January 1, 2018 relating to classification and measurement of particular share-based payment transactions. The adoption of this revision did not have a material impact on the Corporation's consolidated financial statements.

Accounting standards issued but not yet applied

In January 2016, the IASB issued IFRS 16 *Leases*, which will replace IAS 17 *Leases*. Under IFRS 16, a single recognition and measurement model will apply for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. The standard eliminates the classification of leases as either operating leases or finance leases for lessees, essentially treating all leases as finance leases. Short-term leases and leases for low-value assets are exempt from recognition and will continue to be treated as operating leases. The accounting requirements for lessors is substantially unchanged and a lessor will continue to classify leases as either finance leases or operating leases, but disclosure requirements are enhanced. The standard is effective for annual periods beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. IFRS 16 will be adopted by the Corporation on January 1, 2019. The Corporation is currently assessing and evaluating the impact of the standard on the consolidated financial statements. The Corporation anticipates there will be a material impact on the consolidated financial statements and additional new disclosures.

4. SIGNIFICANT ACCOUNTING ESTIMATES, ASSUMPTIONS AND JUDGMENTS

The same accounting estimates, assumptions and judgments were used in the unaudited interim consolidated financial statements as were used in the Corporation's audited consolidated financial statements. Additional estimates, assumptions and judgments for 2018 are outlined below:

(a) Sale and leaseback accounting

On March 22, 2018, the Corporation sold its 100% interest in the Stonefell Terminal and management determined that the sale of the Stonefell Terminal and the subsequent lease of the terminal should be accounted for as a sale and leaseback transaction that resulted in a finance lease.

Determining the measurement of a finance lease asset and obligation is a complex process that involves estimates, assumptions and judgments to determine the fair value of leased assets, and estimates on timing and amount of expected future cash flows and discount rates. Any future changes to the estimated discount rate will not impact the carrying values of the finance lease asset and obligation. The leased asset will be subject to property, plant and equipment impairment reviews at subsequent reporting periods.

5. PROPERTY, PLANT AND EQUIPMENT

	Crude oil	Transportation and storage	Corporate assets	Total
Cost				
Balance as at December 31, 2016	$ 7,878,009	$ 1,610,118	$ 55,983	$ 9,544,110
Additions	478,782	8,645	20,465	507,892
Dispositions	(24,102)	-	-	(24,102)
Change in decommissioning liabilities	(34,599)	(922)	-	(35,521)
Balance as at December 31, 2017	$ 8,298,090	$ 1,617,841	$ 76,448	$ 9,992,379
Additions	143,544	200,224	208	343,976
Transfers to other assets (Note 8)	-	(67,318)	-	(67,318)
Dispositions	-	(1,396,864)	-	(1,396,864)
Change in decommissioning liabilities	(36,781)	(282)	-	(37,063)
Balance as at March 31, 2018	**$ 8,404,853**	**$ 353,601**	**$ 76,656**	**$ 8,835,110**

Accumulated depletion and depreciation				
Balance as at December 31, 2016	$ 1,766,709	$ 110,833	$ 27,134	$ 1,904,676
Depletion and depreciation	436,271	29,801	5,964	472,036
Dispositions	(18,732)	-	-	(18,732)
Balance as at December 31, 2017	$ 2,184,248	$ 140,634	$ 33,098	$ 2,357,980
Depletion and depreciation	101,607	6,857	1,641	110,105
Dispositions	-	(145,987)	-	(145,987)
Balance as at March 31, 2018	**$ 2,285,855**	**$ 1,504**	**$ 34,739**	**$ 2,322,098**
Carrying amounts				
Balance as at December 31, 2017	$ 6,113,842	$ 1,477,207	$ 43,350	$ 7,634,399
Balance as at March 31, 2018	**$ 6,118,998**	**$ 352,097**	**$ 41,917**	**$ 6,513,012**

On March 22, 2018, the Corporation successfully completed the sale of its 50% interest in the Access Pipeline and its 100% interest in the Stonefell Terminal for proceeds of $1.50 billion (net of transaction costs of $18.5 million). As a result of the transaction, the Corporation recognized a gain of $318.4 million on the sale of its 50% interest in the Access Pipeline. The sale of its 100% interest in the Stonefell Terminal has been accounted for as a sale and leaseback transaction that results in a finance lease (Note 10(a)). The $195.9 million net book value of the leased asset is included in transportation and storage assets within property, plant and equipment. The Stonefell Lease Agreement is a 30-year arrangement that secures the Corporation's operational control and exclusive use of 100% of Stonefell Terminal's 900,000 barrel blend and condensate facility.

As at March 31, 2018, property, plant and equipment was assessed for impairment and no impairment was recognized. Included in the cost of property, plant and equipment is $363.7 million of assets under construction (December 31, 2017 – $459.7 million).

6. EXPLORATION AND EVALUATION ASSETS

Cost		
Balance as at December 31, 2016	$	547,752
Additions		1,569
Change in decommissioning liabilities		(493)
Balance as at December 31, 2017	$	548,828
Additions		438
Change in decommissioning liabilities		(705)
Balance as at March 31, 2018	**$**	**548,561**

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 at March 31, 2018, these assets were assessed for impairment within the aggregation of all of the Corporation's CGU's and no impairment has been recognized on exploration and evaluation assets.

7. INTANGIBLE ASSETS

Cost		
Balance as at December 31, 2016	$	112,921
Additions		534
Balance as at December 31, 2017	$	113,455
Additions		(78)
Balance as at March 31, 2018	**$**	**113,377**

Accumulated depreciation		
Balance as at December 31, 2016	$	96,810
Depreciation		3,608
Balance as at December 31, 2017	$	100,418
Depreciation		794
Balance as at March 31, 2018	**$**	**101,212**

Carrying amounts		
Balance as at December 31, 2017	$	13,037
Balance as at March 31, 2018	**$**	**12,165**

As at March 31, 2018, Intangible assets consist of $12.2 million invested in software that is not an integral component of the related computer hardware (December 31, 2017 – $13.0 million). As at March 31, 2018, no impairment has been recognized on these assets.

8. OTHER ASSETS

As at	March 31, 2018	December 31, 2017
Long-term pipeline linefill[a]	**$ 193,769**	$ 122,657
Deferred financing costs	**21,985**	24,134
Interest rate swap[b]	**-**	8,067
	215,754	154,858
Less current portion	**(8,653)**	(9,126)
	$ 207,101	$ 145,732

(a) Long-term pipeline linefill on third party owned pipelines is classified as a long-term asset as these transportation contracts expire between the years 2025 and 2048. As a result of the sale of the Corporation's 50% interest in Access Pipeline and its 100% interest in the Stonefell Terminal on March 22, 2018, $67.3 million of the associated pipeline linefill was transferred from property, plant and equipment to other assets. As at March 31, 2018, no impairment has been recognized on these assets.

(b) In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of its US$1.2 billion senior secured term loan at approximately 5.3%. In conjunction with the March 2018 partial repayment of the senior secured term loan, the interest rate swap was terminated and a realized gain of $17.3 million was recognized (Note 17).

9. LONG-TERM DEBT

As at	March 31, 2018	December 31, 2017
Senior secured term loan (March 31, 2018 – US$234.7 million; due 2023; December 31, 2017 – US$1.226 billion)[a]	**$ 302,722**	$ 1,534,378
6.5% senior secured second lien notes (US$750.0 million; due 2025)	**967,575**	938,850
6.375% senior unsecured notes (US$800.0 million; due 2023)	**1,032,080**	1,001,440
7.0% senior unsecured notes (US$1.0 billion; due 2024)	**1,290,100**	1,251,800
	3,592,477	4,726,468
Less unamortized financial derivative liability discount	**(1,465)**	(4,242)
Less unamortized deferred debt discount and debt issue costs	**(32,316)**	(38,499)
	3,558,696	4,683,727
Less current portion of senior secured term loan	**(15,933)**	(15,460)
	$ 3,542,763	$ 4,668,267

The U.S. dollar denominated debt was translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2901 (December 31, 2017 – US$1 = C$1.2518).

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.

(a) On March 27, 2018, subsequent to the sale of assets, a majority of the net cash proceeds were used to repay approximately $1.2 billion of the senior secured term loan (Note 5).

As at March 31, 2018, the senior secured credit facilities are comprised of a US$235 million term loan and a US$1.4 billion revolving credit facility. The senior secured term loan, credit facilities and second lien notes are secured by substantially all the assets of the Corporation. As at March 31, 2018, no amount has been drawn under the US$1.4 billion revolving credit facility.

The Corporation's letter of credit facility, guaranteed by Export Development Canada, has a limit of US$440 million. Letters of credit under this facility do not consume capacity of the revolving credit facility. As at March 31, 2018, the Corporation has US$146.6 million of unutilized capacity under this facility.

10. PROVISIONS AND OTHER LIABILITIES

As at	March 31, 2018	December 31, 2017
Finance leases[(a)]	$ 130,466	$ -
Onerous contracts provision[(b)]	87,002	92,157
Decommissioning provision[(c)]	62,917	102,530
Deferred lease inducements[(d)]	22,368	22,854
Other long-term liabilities	10,613	15,417
Provisions and other liabilities	313,366	232,958
Less current portion	(27,656)	(27,446)
Non-current portion	$ 285,710	$ 205,512

(a) Finance leases:

As at	March 31, 2018	December 31, 2017
Balance, beginning of year	$ -	$ -
Liabilities incurred	130,446	-
Liabilities settled	(421)	-
Interest expense	441	-
Balance, end of period	$ 130,466	$ -

On March 22, 2018, the Corporation successfully completed the sale of its 100% interest in the Stonefell Terminal. Concurrently, the Corporation entered into a Stonefell Lease Agreement, which is a 30-year arrangement that secures the Corporation's operational control and use of 100% of the Stonefell Terminal. The sale of the Stonefell Terminal and the Stonefell Lease Agreement are accounted for as a sale and leaseback transaction that results in a finance lease. The lease payments are escalated at 1% per year and the Corporation is entitled to unlimited renewal terms. The total undiscounted amount of the estimated future cash flows to settle the lease obligations over the 30-year lease term is $546.0 million. The Corporation has estimated the net present value of the lease obligations using a weighted average credit-adjusted risk-free rate of 13.5%.

The Corporation's minimum lease payments are as follows:

As at	March 31, 2018
Within one year	$ 14,382
Later than one year but not later than five years	64,314
Later than five years	465,993
Minimum lease payments	544,689
Amounts representing finance charges	(414,223)
Present value of net minimum lease payments	$ 130,466

(b) Onerous contracts provision:

As at	March 31, 2018	December 31, 2017
Balance, beginning of year	**$ 92,157**	$ 100,159
Changes in estimated future cash flows	**1,382**	13,337
Changes in discount rates	**(738)**	(2,507)
Liabilities settled	**(6,008)**	(19,569)
Accretion	**209**	737
Balance, end of period	**87,002**	92,157
Less current portion	**(15,850)**	(19,047)
Non-current portion	**$ 71,152**	$ 73,110

As at March 31, 2018, the Corporation has recognized a provision of $87.0 million related to onerous operating lease contracts (December 31, 2017 – $92.2 million). The provision represents the present value of the difference between the minimum future payments that the Corporation is obligated to make under the non-cancellable onerous operating lease contracts and estimated recoveries. The total undiscounted amount of the estimated future cash flows to settle the onerous contracts obligations is $97.9 million (December 31, 2017 - $102.1 million). These cash flows have been discounted using a risk-free discount rate of 2.0% (December 31, 2017 – 1.8%). This estimate may vary as a result of changes in estimated recoveries.

(c) Decommissioning provision:

The following table presents the decommissioning provision associated with the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets:

As at	March 31, 2018	December 31, 2017
Balance, beginning of year	**$ 102,530**	$ 133,924
Changes in estimated future cash flows and settlement dates	**(613)**	(36,314)
Changes in discount rates	**(37,364)**	(19,602)
Liabilities incurred	**260**	19,902
Liabilities disposed	**(976)**	-
Liabilities settled	**(2,621)**	(2,403)
Accretion	**1,701**	7,023
Balance, end of period	**62,917**	102,530
Less current portion	**(9,859)**	(6,386)
Non-current portion	**$ 53,058**	$ 96,144

The decommissioning provision represents the present value of the estimated future costs for the reclamation and abandonment of the Corporation's property, plant and equipment and exploration and evaluation assets. The total undiscounted amount of the estimated future cash flows to settle the decommissioning obligations is $784.6 million (December 31, 2017 - $859.1 million). The Corporation has estimated the net present value of the decommissioning obligations using a weighted average credit-adjusted risk-free rate of 14.0% (December 31, 2017 – 9.5%).

(d) Deferred lease inducements:

Deferred lease inducements of $22.4 million will be amortized and recognized as a reduction to general and administrative expense over the respective terms of the Corporation's office leases.

11. SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares.

Changes in issued common shares are as follows:

	Three months ended March 31, 2018			Year ended December 31, 2017		
	Number of shares		**Amount**	**Number of shares**		**Amount**
Balance, beginning of year	**294,103,943**	**$**	**5,403,978**	226,467,107	$	4,878,607
Shares issued	**-**		**-**	66,815,000		517,816
Share issue costs net of tax	**-**		**-**	-		(15,698)
Issued upon vesting and release of RSUs and PSUs	**985**		**-**	821,836		23,253
Balance, end of period	**294,104,928**	**$**	**5,403,978**	294,103,943	$	5,403,978

12. STOCK-BASED COMPENSATION

The Corporation has a number of stock-based compensation plans which include stock options, restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units ("DSUs"). Further detail on each of these plans is outlined below.

(a) Cash-settled plans

i. Restricted share units and performance share units:

RSUs granted under the cash-settled RSU plan generally vest over a three-year period. PSUs granted under the cash-settled RSU plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors within a target range.

RSUs and PSUs outstanding:

Three months ended March 31, 2018	
Outstanding, beginning of year	**5,310,073**
Vested and released	**(7,372)**
Forfeited	**(41,395)**
Outstanding, end of period	**5,261,306**

ii. Deferred share units outstanding:

The Deferred Share Unit Plan allows for the granting of DSUs to directors of the Corporation. As at March 31, 2018, there were 284,871 DSUs outstanding (December 31, 2017 – 284,871 DSUs outstanding).

As at March 31, 2018, the Corporation has recognized a liability of $13.8 million relating to the fair value of RSUs, PSUs and DSUs (December 31, 2017 – $14.3 million).

(b) Equity-settled plans

i. Stock options outstanding:

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

Three months ended March 31, 2018	**Stock options**	**Weighted average exercise price**
Outstanding, beginning of year	**8,896,003**	**$ 23.81**
Forfeited	**(71,800)**	**31.01**
Expired	**(22,800)**	**45.01**
Outstanding, end of period	**8,801,403**	**$ 23.70**

ii. Restricted share units and performance share units:

RSUs granted under the equity-settled Restricted Share Unit Plan generally vest annually over a three-year period. PSUs granted under the equity-settled Restricted Share Unit Plan generally vest on the third anniversary of the grant date, provided that the Corporation satisfies certain performance criteria identified by the Corporation's Board of Directors within a target range.

RSUs and PSUs outstanding:

Three months ended March 31, 2018	
Outstanding, beginning of year	**6,307,228**
Forfeited	**(81,309)**
Outstanding, end of period	**6,225,919**

(c) Stock-based compensation

	Three months ended March 31	
	2018	**2017**
Cash-settled expense (recovery)[(i)]	**$ (291)**	$ (1,223)
Equity-settled expense	**6,129**	3,510
Stock-based compensation	**$ 5,838**	$ 2,287

(i) Cash-settled RSUs and PSUs are accounted for as liability instruments and are measured at fair value based on the market value of the Corporation's common shares at each period end. Fluctuations in the fair value are recognized during the period in which they occur.

13. REVENUES

	Three months ended March 31	
	2018	**2017**
		Revised (Note 3)
Petroleum revenue[(i)]:		
Proprietary	**$ 672,890**	$ 489,388
Third-party	**43,643**	66,773
Petroleum revenue	**716,533**	556,161
Royalties	**(8,508)**	(5,691)
Petroleum revenue, net of royalties	**$ 708,025**	$ 550,470
Power revenue	**$ 9,956**	$ 6,356
Transportation revenue	**2,610**	2,953
Other revenue	**$ 12,566**	$ 9,309
	$ 720,591	$ 559,779

(i) 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".

(a) Disaggregation of revenue from contracts with customers

The Corporation recognizes revenue upon delivery of goods and services in the following geographic regions:

	Petroleum Revenue		Total
	Proprietary	**Third-party**	
Three months ended March 31, 2018			
Country:			
Canada	**$ 429,322**	**$ 41,029**	**$ 470,351**
United States	**243,568**	**2,614**	**246,182**
	$ 672,890	**$ 43,643**	**$ 716,533**
Three months ended March 31, 2017			
Country:			
Canada	$ 314,696	$ 36,863	$ 351,559
United States	174,692	29,910	204,602
	$ 489,388	$ 66,773	$ 556,161

Other revenue recognized during the three months ended March 31, 2018 and 2017 is attributed to Canada.

(b) Revenue-related assets

The Corporation has recognized the following revenue-related assets in trade receivables and other:

As at	March 31, 2018	December 31, 2017
Petroleum revenue	$ 260,593	$ 244,330
Other revenue	3,893	2,960
Total revenue-related assets	$ 264,486	$ 247,290

Accrued receivables are typically settled within 30 days. As at March 31, 2018, and December 31, 2017, no impairment has been recognized on revenue-related receivables.

14. DILUENT AND TRANSPORTATION

	Three months ended March 31	
	2018	2017
Diluent expense	$ 332,966	$ 234,399
Transportation expense	51,976	46,898
Diluent and transportation	$ 384,942	$ 281,297

15. PURCHASED PRODUCT AND STORAGE

	Three months ended March 31	
	2018	2017 Revised (Note 3)
Third-party purchased product	$ 42,429	$ 65,542
Blend purchases	48,798	-
Purchased product and storage	$ 91,227	$ 65,542

16. FOREIGN EXCHANGE LOSS (GAIN), NET

	Three months ended March 31	
	2018	2017
Unrealized foreign exchange loss (gain) on:		
Long-term debt	$ 138,784	$ (39,758)
Other	2,514	3,051
Unrealized net loss (gain) on foreign exchange	141,298	(36,707)
Realized loss (gain) on foreign exchange	2,010	(2,313)
Realized loss (gain) on foreign exchange derivatives[(a)]	(35,362)	-
Foreign exchange loss (gain), net	$ 107,946	$ (39,020)

C$ equivalent of 1 US$		
Beginning of period	1.2518	1.3427
End of period	1.2901	1.3322

(a) On February 8, 2018, the Corporation entered into forward currency contracts to manage the foreign exchange risk on expected Canadian dollar denominated asset sale proceeds designated for U.S. dollar denominated long-term debt repayment. The forward currency contracts were settled on March 22, 2018, resulting in a realized gain of $35.4 million.

17. NET FINANCE EXPENSE

	Three months ended March 31	
	2018	**2017**
Total interest expense	**$ 82,865**	$ 93,274
Total interest income	**(1,740)**	(806)
Net interest expense	**81,125**	92,468
Accretion on provisions	**1,910**	1,856
Unrealized loss (gain) on derivative financial liabilities	**2,976**	(2,241)
Realized loss (gain) on interest rate swaps[a]	**(17,312)**	-
Net finance expense	**$ 68,699**	$ 92,083

(a) In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of its US$1.2 billion senior secured term loan at approximately 5.3%. In conjunction with the partial repayment of the senior secured term loan on March 27, 2018, the interest rate swap was terminated and a realized gain of $17.3 million was recognized.

18. INCOME TAX EXPENSE (RECOVERY)

	Three months ended March 31	
	2018	**2017**
Current income tax expense (recovery)	**$ 116**	$ (284)
Deferred income tax expense (recovery)	**(29,774)**	10,979
Income tax expense (recovery)	**$ (29,658)**	$ 10,695

The Corporation has recognized a deferred tax asset of $214.4 million (December 31, 2017 – $182.9 million). Future taxable income is expected to be sufficient to realize the deferred tax asset. The deferred tax asset is reviewed at each balance sheet date to assess whether it is probable that the related tax benefit will be realized.

19. SUPPLEMENTAL CASH FLOW DISCLOSURES

	Three months ended March 31	
	2018	**2017**
Cash provided by (used in):		
Trade receivables and other	**$ (8,945)**	$ 32,734
Inventories	**(18,315)**	(11,825)
Accounts payable and accrued liabilities	**48,800**	(9,437)
	$ 21,540	$ 11,472
Changes in non-cash working capital relating to:		
Operating	**$ 8,136**	$ 8,187
Investing	**13,404**	3,285
	$ 21,540	$ 11,472
Cash and cash equivalents:[(a)]		
Cash	**$ 281,029**	$ 250,410
Cash equivalents	**394,087**	298,571
	$ 675,116	$ 548,981
Cash interest paid	**$ 127,792**	$ 115,983

(a) As at March 31, 2018, C$244.4 million of the Corporation's total cash and cash equivalents balance was held in U.S. dollars (March 31, 2017 – C$71.4 million). The U.S. dollar cash and cash equivalents balance has been translated into Canadian dollars at the period end exchange rate of US$1 = C$1.2901 (March 31, 2017 – US$1 = C$1.3322).

The following table reconciles long-term debt to cash flows arising from financing activities:

	Long-term debt[(i)]
Balance as at December 31, 2017	$ 4,683,727
Cash changes:	
Payments on term loan	(1,272,775)
Non-cash changes:	
Unrealized loss (gain) on foreign exchange	138,784
Amortization of financial derivative liability discount	684
Amortization of deferred debt discount and debt issue costs	1,895
IFRS 9 adjustment to deferred debt discount and debt issue costs (Note 3)	6,381
Balance as at March 31, 2018	**$ 3,558,696**

(i) Long-term debt, including the current portion of long-term debt.

20. NET EARNINGS (LOSS) PER COMMON SHARE

	Three months ended March 31	
	2018	**2017**
Net earnings (loss)	**$ 140,573**	$ 1,588
Weighted average common shares outstanding[(a)]	**294,244,791**	274,164,421
Dilutive effect of stock options, RSUs and PSUs	**3,417,130**	352,953
Weighted average common shares outstanding – diluted	**297,661,921**	274,517,374
Net earnings (loss) per share, basic	**$ 0.48**	$ 0.01
Net earnings (loss) per share, diluted	**$ 0.47**	$ 0.01

(a) Weighted average common shares outstanding for the three months ended March 31, 2018 includes 139,863 PSUs not yet released (three months ended March 31, 2017 – 184,425 PSUs).

21. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The financial instruments recognized on the consolidated balance sheet are comprised of cash and cash equivalents, trade receivables and other, commodity risk management contracts, the interest rate swap included within other assets, accounts payable and accrued liabilities, derivative financial liabilities and finance leases included within provisions and other liabilities and long-term debt. As at March 31, 2018, commodity risk management contracts and derivative financial liabilities were classified as fair value through profit and loss; cash and cash equivalents, trade receivables and other, accounts payable and accrued liabilities, finance leases and long-term debt were 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 long-term debt, finance leases, derivative financial liabilities, derivative financial assets and commodity risk management contracts:

As at March 31, 2018	Carrying amount	Fair value measurements using Level 1	Level 2	Level 3
Recurring measurements:				
Financial liabilities				
Long-term debt[(i)] (Note 9)	**$ 3,592,477**	**$ -**	**$ 3,165,776**	**$ -**
Finance leases (Note 10)	**$ 130,466**	**$ -**	**$ -**	**$ 130,466**
Derivative financial liabilities (Note 10)	**$ 937**	**$ -**	**$ 937**	**$ -**
Commodity risk management contracts	**$ 126,681**	**$ -**	**$ 126,681**	**$ -**

As at December 31, 2017	Carrying amount	Fair value measurements using Level 1	Level 2	Level 3
Recurring measurements:				
Financial assets				
Interest rate swap (Note 8)	$ 8,067	$ -	$ 8,067	$ -
Financial liabilities				
Long-term debt[(i)] (Note 9)	$ 4,726,468	$ -	$ 4,415,238	$ -
Derivative financial liabilities (Note 10)	$ 6,028	$ -	$ 6,028	$ -
Commodity risk management contracts	$ 68,649	$ -	$ 68,649	$ -

(i) Includes the current and long-term portions.

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

As at March 31, 2018, the Corporation did not have any financial instruments measured at Level 1 fair value.

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

The estimated fair value of long-term debt is derived using quoted prices in an inactive market from a third-party independent broker.

The fair value of commodity risk management contracts and derivative financial assets and liabilities are derived using third-party 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 forward prices for commodities, 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.

Level 3 fair value measurements are based on unobservable information.

The estimated fair value of finance leases is based on recently observed transactions, or calculated by discounting the expected future contractual cash flows using a discount rate based on either contractual terms or market rates for instruments of similar maturity and credit risk.

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.

(b) Commodity price risk management:

The Corporation enters into derivative financial instruments to manage commodity price risk. The use of the financial commodity risk management contracts is governed by a Risk Management Committee that follows guidelines and limits approved by the Board of Directors. The Corporation does not use financial derivatives for speculative purposes. Financial commodity risk management contracts are measured at fair value, with gains and losses on re-measurement included in the consolidated statement of earnings and comprehensive income in the period in which they arise.

The Corporation had the following financial commodity risk management contracts relating to crude oil sales outstanding as at March 31, 2018:

As at March 31, 2018	Volumes (bbls/d)(i)	Term	Average Price (US$/bbl)(i)
Fixed Price:			
WTI(ii) Fixed Price	33,000	Apr 1, 2018 – Jun 30, 2018	$53.99
WTI Fixed Price	34,000	Jul 1, 2018 – Dec 31, 2018	$55.25
WTI:WCS(iii) Fixed Differential	47,000	Apr 1, 2018 – Jun 30, 2018	$(14.52)
WTI:WCS Fixed Differential	32,000	Jul 1, 2018 – Dec 31, 2018	$(14.68)
Collars:			
WTI Collars	39,500	Apr 1, 2018 – Jun 30, 2018	$46.65 – $54.88
WTI Collars	32,500	Jul 1, 2018 – Dec 31, 2018	$46.64 – $54.52

The Corporation had the following financial commodity risk management contracts relating to condensate purchases outstanding as at March 31, 2018:

As at March 31, 2018	Volumes (bbls/d)(i)	Term	Average % of WTI(i)
Mont Belvieu fixed % of WTI	1,000	Apr 1, 2018 – Jun 30, 2018	92.3%
Mont Belvieu fixed % of WTI	500	Jul 1, 2018 – Sep 30, 2018	93.5%

(i) The volumes and prices in the above tables represent averages for various contracts with differing terms and prices. The average price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.
(ii) West Texas Intermediate ("WTI") crude oil
(iii) Western Canadian Select ("WCS") crude oil blend

The Corporation's financial commodity risk management contracts are subject to master agreements that create a legally enforceable right to offset, by counterparty, the related financial assets and financial liabilities on the Corporation's balance sheet in all circumstances.

The following table provides a summary of the Corporation's unrealized offsetting financial commodity risk management positions:

As at	March 31, 2018			December 31, 2017		
	Asset	Liability	Net	Asset	Liability	Net
Gross amount	**$ -**	**$ (227,839)**	**$ (227,839)**	$ -	$ (184,175)	$ (184,175)
Amount offset	**-**	**101,158**	**101,158**	-	115,526	115,526
Net amount	**$ -**	**$ (126,681)**	**$ (126,681)**	$ -	$ (68,649)	$ (68,649)

The following table provides a reconciliation of changes in the fair value of the Corporation's financial commodity risk management assets and liabilities from January 1 to March 31:

As at March 31	2018	2017
Fair value of contracts, beginning of year	**$ (68,649)**	$ (30,313)
Fair value of contracts realized	**17,719**	(1,512)
Change in fair value of contracts	**(75,751)**	61,111
Fair value of contracts, end of period	**$ (126,681)**	$ 29,286

The following table summarizes the financial commodity risk management gains and losses:

	Three months ended March 31	
	2018	2017
Realized loss (gain) on commodity risk management	**$ 17,719**	$ (1,512)
Unrealized loss (gain) on commodity risk management	**58,032**	(59,599)
Commodity risk management loss (gain)	**$ 75,751**	$ (61,111)

The following table summarizes the sensitivity of the earnings before income tax impact of fluctuating commodity prices on the Corporation's open financial commodity risk management positions in place as at March 31, 2018:

Commodity	Sensitivity Range	Increase	Decrease
Crude oil commodity price	± US$1.00 per bbl applied to WTI contracts	$ (24,297)	$ 24,297
Crude oil differential price(i)	± US$1.00 per bbl applied to WCS differential contracts	$ 13,114	$ (13,114)
Condensate percentage	± 1% in condensate price as a percentage of $US WTI price per bbl applied to condensate contracts	$ 110	$ (110)

(i) As the WCS differential is expressed as a discount to WTI, an increase in the differential results in a lower WCS price and a decrease in the differential results in a higher WCS price.

The Corporation entered into the following financial commodity risk management contracts relating to crude oil sales subsequent to March 31, 2018. As a result, these contracts are not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to March 31, 2018	Volumes (bbls/d)(i)	Term	Average Price (US$/bbl)(i)
Fixed Price:			
WTI:WCS Fixed Differential	1,000	Jul 1, 2018 – Dec 31, 2018	$(21.25)
Options:			
Purchased WTI Calls	13,800	May 1, 2018 – May 31, 2018	$69.70

The Corporation entered into the following financial commodity risk management contracts relating to condensate purchases subsequent to March 31, 2018. As a result, these contracts are not reflected in the Corporation's Interim Consolidated Financial Statements:

Subsequent to March 31, 2018	Volumes (bbls/d)(i)	Term	Average Price (US$/bbl)(i)
Mont Belvieu fixed % of WTI	750	Jul 1, 2018 – Dec 31, 2018	$65.70

Subsequent to March 31, 2018	Volumes (bbls/d)(i)	Term	Average % of WTI(i)
Mont Belvieu fixed % of WTI	1,500	Jul 1, 2018 – Sep 30, 2018	93.2%

(i) The volumes, prices and percentages in the above tables represent averages for various contracts with differing terms and prices. The average price and percentages for the portfolio may not have the same payment profile as the individual contracts and are provided for indicative purposes.

(c) Credit risk management:

The Corporation applies the simplified approach to providing for expected credit losses prescribed by IFRS 9, which permits the use of the lifetime expected loss provision for all trade receivables. The Corporation uses a combination of historical and forward looking information to determine the appropriate loss allowance provisions. 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 the 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. The Corporation has experienced no material loss in relation to trade receivables.

(d) Interest rate risk management:

The Corporation is exposed to interest rate cash flow risk on its floating rate long-term debt and periodically enters into interest rate swap contracts to manage its floating to fixed interest rate mix on long-term debt. In the third quarter of 2017, the Corporation entered into an interest rate swap contract to effectively fix the interest rate on US$650.0 million of the US$1.2 billion senior secured term loan at approximately 5.3%. Interest rate swaps are classified as derivative financial assets and liabilities and measured at fair value, with gains and losses on re-measurement included as a component of net finance expense in the period in which they arise. In conjunction with the partial repayment of the senior secured term loan on March 27, 2018, the interest rate swap was terminated and a realized gain of $17.3 million was recognized (Note 17).

22. GEOGRAPHICAL DISCLOSURE

As at March 31, 2018, the Corporation had non-current assets related to operations in the United States of $106.8 million (December 31, 2017 – $101.7 million). For the three months ended March 31, 2018, petroleum revenue related to operations in the United States was $246.2 million (three months ended March 31, 2017 – $204.6 million).

23. COMMITMENTS AND CONTINGENCIES

(a) Commitments

The Corporation's commitments are enforceable and legally binding obligations to make payments in the future for goods and services. These items exclude amounts recorded on the consolidated balance sheet. The Corporation had the following commitments as at March 31, 2018:

	2018	2019	2020	2021	2022	Thereafter	Total
Transportation and storage(i)	$ 210,853	$ 300,300	$ 323,702	$ 428,728	$ 438,780	$ 6,601,475	$ 8,303,838
Office lease rentals(ii)	8,147	10,863	11,286	11,286	11,286	107,667	160,535
Diluent purchases	381,871	369,281	20,217	20,162	20,162	16,792	828,485
Other operating commitments	9,667	13,648	11,077	9,377	8,291	54,298	106,358
Capital commitments	11,037	-	-	-	-	-	11,037
Commitments	**$ 621,575**	**$ 694,092**	**$ 366,282**	**$ 469,553**	**$ 478,519**	**$ 6,780,232**	**$ 9,410,253**

(i) This represents transportation and storage commitments from 2018 to 2048, including the Access Pipeline TSA, and various pipeline commitments which are awaiting regulatory approval and are not yet in service. Excludes finance leases recognized on the consolidated balance sheet (Note 10(a)).

(ii) Excludes amounts for which an onerous contracts provision has been recognized on the consolidated balance sheet (Note 10(b)).

(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.

The Corporation is the defendant to a statement of claim originally filed in 2014 in relation to legacy issues involving a unit train transloading facility. The claim was amended in the fourth quarter of 2017 asserting a significant increase to damages claimed. The Corporation continues to view this three year old claim, and the recent amendments, as without merit and will defend against all such claims.