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2014 | Q2 INTERIM REPORT

ENMAX Corporation | Three & Six Months Ended June 30, 2014

HIGHLIGHTS

(millions of dollars, unless otherwise noted)	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Revenues	767.4	872.6	1,769.9	1,716.0
Operating margin [1]	200.9	128.9	378.1	309.5
Net earnings	63.6	185.2	99.5	243.5
Net earnings from continuing operations	63.6	8.2	99.5	63.3
Earnings before interest, income tax, depreciation and amortization (EBITDA) [1]	113.2	227.3	213.4	337.0
Earnings before interest and income taxes (EBIT) [1]	70.2	6.7	128.6	71.7
Cash flow from operations [1]	109.2	28.4	207.2	124.9
Total assets			4,536.8	4,818.2
Return on assets [2]			8.0%	12.2%
Return on equity [3]			8.6%	16.1%
Total recordable injury frequency (TRIF)			0.51	1.22
Capital expenditures	95.1	118.3	171.6	230.1
Electricity sold to customers (Gigawatts hours [GWh])	4,913	5,014	10,320	10,427
Employees (#) [4]			1,917	1,871

(1) Non-GAAP financial measure. See discussion that follows in the Management's Discussion & Analysis (MD&A).

(2) Return on assets (ROA) is equal to net earnings before after-tax interest charges for the 12-month rolling period divided by average total assets (adjusted for capital assets under construction and current liabilities) for the 12-month rolling period. 2013 ROA includes the $175.9 million gain on sale of Envision recorded in Q2 2013.

(3) Return on equity (ROE) is equal to net earnings for the 12-month rolling period divided by average shareholder's equity for the last 12 month rolling period. 2013 ROE includes the $175.9 million gain on sale of Envision recorded in Q2 2013.

(4) Employee count is total employees.

CAUTION TO READER

This document contains statements about future events and financial and operating results of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) that are forward looking. By their nature, forward-looking statements require the Corporation to make assumptions and are subject to inherent risks and uncertainties. There is significant risk that predictions and other forward-looking statements will not prove to be accurate. Readers are cautioned not to place undue reliance on forward-looking statements as a number of factors could cause actual future results, conditions, actions or events to differ materially from financial and operating targets, expectations, estimates or intentions expressed in the forward-looking statements.

When used in this interim report, the words "may," "would," "could," "will," "intend," "plan," "anticipate," "believe," "seek," "propose," "estimate," "expect" and similar expressions, as they relate to the Corporation or an affiliate of the Corporation, are intended to identify forward-looking statements. Such statements reflect the Corporation's current views with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation's actual results, performance or achievements to vary from those described in this interim report. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this interim report. Intended, planned, anticipated, believed, estimated or expected and other forward-looking statements included in this interim report should not be unduly relied upon. These statements speak only as of the date of this interim report. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law, and reserves the right to change, at any time at its sole discretion, the practice of updating annual targets and guidance. Targets for 2014 are described in the Management's Discussion & Analysis (MD&A) Outlook section. This interim report should be read in conjunction with ENMAX's 2013 Financial Report.

Factors that could cause actual results to differ materially include, but are not limited to, the following:

- competitive factors and pricing pressures, including electricity supply and demand in the Alberta power market and fluctuations in the pricing of natural gas in the North American market;
- the availability of the Corporation's generation assets to produce power;
- regulatory developments as they relate to transmission and distribution rate-making and the impact of deregulation in the industry;
- changes in environmental and other legislation;
- human resources, including possible labour disruptions;
- financing and debt requirements, including ability to carry out refinancing activities;
- tax matters, including acceleration or deferral of required cash payments, realization of timing differences and potential reassessments by tax authorities;
- litigation and legal matters;
- business continuity events (including man-made and natural threats);
- economic growth and fluctuations as they relate to the natural-resource-based Alberta economy;
- weather and climate;
- changes in customers' wants and needs due to evolving technologies and a movement to more environmentally sensitive ways of living; and
- other risk factors discussed herein and listed from time to time in ENMAX's reports and other public disclosure documents.

For further information on the Corporation's risks, see the MD&A Risk Management and Uncertainties section included in ENMAX's 2013 Financial Report.

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

This MD&A, dated August 27, 2014, is a review of the results of operations of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) for the three and six months ended June 30, 2014, compared with the same periods in 2013, and of the Corporation's financial condition and future prospects. This discussion contains forward-looking information that is qualified by reference to and should be read in light of the caution to reader previously mentioned.

ENMAX's consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The Corporation has chosen to defer the adoption of International Financial Reporting Standards (IFRS) as permitted by the Accounting Standards Board (AcSB).

The Consolidated Financial Statements and MD&A were reviewed by ENMAX's Audit, Finance and Risk Committee, and the Consolidated Financial Statements were approved by ENMAX's Board of Directors (the Board). All amounts are in Canadian dollars unless otherwise specified.

The Corporation reports on certain non-GAAP financial measures such as operating margin and funds from operations that are used by management to evaluate performance of business units and segments. Because non-GAAP financial measures do not have a standardized meaning, the Corporation has defined and reconciled them with their nearest GAAP measure. For the reader's reference, the definition, calculation and reconciliation of consolidated non-GAAP financial measures is provided in the Non-GAAP Financial Measures section.

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OVERALL FINANCIAL PERFORMANCE

SELECTED CONSOLIDATED FINANCIAL INFORMATION

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars, unless otherwise noted)	2014	2013	2014	2013
EBIT [1]	**70.2**	6.7	**128.6**	71.7
Net earnings	**63.6**	185.2	**99.5**	243.5
Net earnings from continuing operations	**63.6**	8.2	**99.5**	63.3

(1) Non-GAAP financial measure. See discussion that follows in Non-GAAP Financial Measures section.

ENMAX's consolidated net earnings for the three and six months ended June 30, 2014, is $63.6 million and $99.5 million, respectively, compared with $185.2 million and $243.5 million, respectively, for the three and six months ended June 30, 2013. The decrease in earnings for the three and six months ended June 30, 2014, is primarily due to the sale of ENMAX Envision Inc. (Envision) on April 30, 2013 for a gain of $175.9 million. Contributing to the decreased earnings is a decrease in electricity margins driven by lower realized prices and decreased realized gains on hedges, and foreign exchange losses. These unfavourable variances were offset partially by increases in transmission and distribution margins as a result of the approval of interim rates for 2014 and a ruling on a recovery of earnings on prior period invested capital. In addition, the unusual power purchase arrangement (PPA) outages noted below had less of a negative impact on 2014 results compared with 2013. The decrease in earnings for the six months ended June 30, 2014, is further impacted by an increase in interest expense of $20.7 million upon settlement of interest rate swaps associated with an early repayment of long-term debt and an increase in operations, maintenance and administration (OM&A) costs. We expect benefits from the repayment in the form of a lower cost of borrowing in future periods.

Results of operations are not necessarily indicative of future performance due to fluctuating commodity prices, the performance and retirement of existing generation facilities, and the addition of new generation facilities. Further details on specific operations can be found in the Business Segment Results section of this report.

UNUSUAL ITEMS INCLUDED IN RESULTS

PPA OUTAGES

On January 31, 2014, the Keephills Unit 2 generator was removed from service by its operator, TransAlta Corporation (TransAlta). Keephills Unit 2 provides ENMAX Energy with approximately 340 megawatts (MW) of electricity through a PPA. On November 27, 2013, TransAlta claimed force majeure under the Keephills PPA with respect to this planned outage. The Keephills Unit 2 generator returned to service on March 15, 2014. ENMAX has not accepted or agreed to the claim of force majeure in relation to this outage and we anticipate ENMAX will enter into a dispute resolution process with TransAlta in accordance with the terms of the PPA. For the six months ended June 30, 2014, the Keephills Unit 2 outage impact was $17.4 million. There was no impact on second quarter earnings.

On March 5, 2013, the Keephills Unit 1 generator was removed from service by its operator, TransAlta . Keephills Unit 1 provides ENMAX Energy with approximately 340 MW of electricity through a PPA. On March 26, 2013, TransAlta claimed force majeure under the Keephills PPA. Under a force majeure, ENMAX is not compensated for the outage by the owner for the duration of the outage but is relieved from paying certain capacity charges to the plant owner for the duration of the event. The Keephills Unit 1 generator returned to service on October 5, 2013. ENMAX has not accepted or agreed to the claim of force majeure in relation to this outage, and we anticipate ENMAX will enter into a dispute resolution process with TransAlta in accordance with the terms of the PPA. For the three and six months ended June 30, 2013, the Keephills Unit 1 outage impact was $63.5 million and $73.9 million, respectively.

FLOOD RESPONSE

In June 2013, southern Alberta experienced significant flooding. In coordination with the Calgary Emergency Management Agency and government agencies, ENMAX Power disconnected and subsequently restored power to affected customers to ensure the safety of citizens. The disconnection and restoring of power minimized damage to ENMAX Power infrastructure and minimized the impact on citizens and damage to business property. For the three and six months ended June 30, 2013, the flood response impact was $2.3 million.

FINANCIAL RESULTS

EBIT FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2014, COMPARED WITH THE SAME PERIODS IN 2013

(millions of dollars)	Three Months Ended	Six Months Ended
EBIT for the period ended June 30, 2013	6.7	71.7
Unusual items included in results:		
2013 Keephills Unit 1 outage	63.5	73.9
2014 Keephills Unit 2 outage	-	(17.4)
2013 Flood response	2.3	2.3
Increased (decreased) margins attributable to:		
Electricity, excluding Keephills outage	(20.8)	(26.4)
Natural gas	2.0	1.7
Transmission and distribution	21.2	34.2
Contractual services and other	6.1	2.6
Increased expenses:		
OM&A	(0.8)	(5.7)
Foreign exchange	(10.0)	(6.7)
Amortization	-	(1.6)
EBIT for the period ended June 30, 2014	70.2	128.6

Normalized electricity margins (electricity margins excluding Keephills outages) for the three months ended June 30, 2014, decreased $20.8 million to $104.0 million from $124.8 million in the same period in 2013. For the six months ended June 30, 2014, normalized electricity margins decreased $26.4 million to $207.6 million from $234.0 million in the same period in 2013. The decreased margins in the three and six months ended June 30, 2014, were driven primarily by lower prices realized on sales and a decrease in realized gains on hedges. In addition, higher natural gas prices contributed to lower electricity margins as it increased the cost to run our natural gas-fired plants. This was partially offset by higher volumes on commercial and residential fixed price contracts.

Natural gas margins for the three months ended June 30, 2014, increased $2.0 million to $6.7 million from $4.7 million for the three months ended June 30, 2013. For the six months ended June 30, 2014, natural gas margins increased $1.7 million to $20.0 million from $18.3 million in the same period in 2013. This increase in the three and six months ended June 30, 2014, is due to higher realized sales price and higher volumes sold. This favourable impact is partially offset by the higher cost of natural gas supply.

For the three months ended June 30, 2014, transmission and distribution margins increased $21.2 million to $75.0 million from the $53.8 million recorded in the same period in 2013. For the six months ended June 30, 2014, transmission and distribution margins increased $34.2 million to $139.9 million from $105.7 million in the same period in 2013. The increased margin in the three and six months ended June 30, 2014, is due primarily to an increase in transmission and distribution tariffs and an Alberta Utilities Commission (AUC) ruling received in the second quarter of 2014 approving recovery of earnings on transmission capital invested in prior periods.

For the three months ended June 30, 2014, margin from contractual services and other sources increased $6.1 million to $15.2 million from $9.1 million compared to the same period in 2013. The increase is mainly due to increased activity on residential and commercial developer projects and the progression of the Tuscany-Rockyridge LRT expansion project. For the six months ended June 30, 2014, contractual services and other revenues increased $2.6 million to $28.0 million from $25.4 million in the same period in 2013. The increase is mainly due to the increased margins from the three months ended June 30, 2014, as discussed, partially offset by the prior comparative period's recognition of cost recoveries associated with ENMAX's disposition of a 25 per cent interest in Shepard Energy Center (Shepard) to Capital Power LP (CPLP).

Normalized OM&A (OM&A excluding flood costs) for the three months ended June 30, 2014, increased $0.8 million to $82.6 million from $81.8 million in the second quarter of 2013. For the six months ended June 30, 2014, OM&A costs increased $5.7 million to $164.5 million from $158.8 million in the same period in 2013. The increase in the three and six months ended June 30, 2014, was due to an increase in staff costs, offset by a decrease in operating and maintenance expense and advertising expense. In the prior year, OM&A costs were higher due to a planned maintenance outage at ENMAX's Calgary Energy Centre (CEC).

For the three months ended June 30, 2014, a net foreign exchange loss of $5.1 million was recognized compared to a gain of $4.9 million in the same period of 2013. For the six months ended June 30, 2014, a foreign exchange loss of $0.2 million was experienced as compared to a gain of $6.5 million in the same period in 2013. Foreign exchange gains or losses are primarily the result of net realized and unrealized gains and losses on equipment purchases and service agreements denominated in foreign currencies and related hedges.

Amortization expense for the three months ended June 30, 2014, was $43.0 million, which is consistent with the same period in 2013. For the six months ended June 30, 2014, amortization expense increased $1.6 million to $84.8 million from $83.2 million in the same period in 2013. The increased charges were primarily the result of new assets placed into service.

OTHER NET EARNINGS ITEMS

For the three months ended June 30, 2014, interest expense decreased $1.0 million to $5.3 million from $6.3 million for the same period in 2013. Interest expense increased $19.9 million to $33.0 million from $13.1 million for the six months ended June 30, 2014, compared to the six months ended June 30, 2013. On March 17, 2014, $200.6 million of non-recourse term financing and $35.6 million of a fixed-for-floating interest rate swap related to CEC was repaid prior to maturity on September 2026. The increase in the six months ended June 30, 2014, interest expense was primarily due to $20.7 million of settlement costs associated with the termination of the interest rate swaps. The decrease in the three months ended June 30, 2014, is related to a lower cost of borrowing resulting from the repayment of this debt.

Current and future income tax costs for the three months ended June 30, 2014, increased $9.1 million to an expense of $1.3 million from a recovery of $7.8 million for the same period in 2013. For the six months ended June 30, 2014, income tax expense increased $0.8 million to a recovery of $3.9 million from a recovery of $4.7 million for the same period in 2013. The increase in income tax was primarily due to higher income in taxable entities.

For the three months ended June 30, 2014, there were no earnings from discontinued operations compared to $1.1 million in the same period in 2013. For the six months ended June 30, 2014, there were no earnings from discontinued operations compared to $4.3 million in the same period in 2013. Earnings from discontinued operations in the three and six months ended June 30, 2013, relate to the Envision business unit that was sold on April 30, 2013.

OTHER COMPREHENSIVE INCOME (OCI)

OCI illustrates earnings under the assumption of full income recognition of gains and losses on the market value of securities and derivatives otherwise treated as hedges of future period revenues and expenses. ENMAX uses derivatives to hedge electricity, natural gas, interest rate and foreign exchange exposures. For the three and six months ended June 30, 2014, OCI totalled a loss of $2.3 million and a gain of $17.1 million, respectively, compared with gains of $12.0 million and $16.8 million, respectively, for the same periods in 2013. OCI for the three and six months ended June 30, 2014, primarily reflects the fair value changes in electricity positions and settlement of interest rate swaps and commodity positions.

BUSINESS SEGMENT RESULTS

EBIT

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	2014	2013	2014	2013
ENMAX Energy	**36.1**	(5.7)	**72.9**	43.0
ENMAX Power	**33.0**	11.4	**53.3**	27.1
Corporate & intersegment eliminations	**1.1**	1.0	**2.4**	1.6
EBIT	**70.2**	6.7	**128.6**	71.7

ENMAX ENERGY

ENMAX Energy, which includes various legal entities and divisions, operates in Alberta's competitive energy market providing electricity, natural gas, district heating, energy management and renewable energy products to residential, commercial and industrial customers.

Our core strategy for ENMAX Energy is to grow our customer base across the province of Alberta and invest in the power generation facilities required to serve our electricity customers. We supply electricity through our own wind and natural gas-fired generation facilities and PPAs at Battle River and Keephills. We balance our energy portfolio needs through the purchase and sale of electricity and natural gas from and into wholesale Alberta markets. ENMAX Energy provides customers with competitive energy products and services with a focus on longer-term fixed electricity contracts. These contracts link our customer demand to our generating assets, which results in relatively stable margins, even during times of volatile wholesale electricity prices.

BUSINESS UPDATE

As discussed in the Overall Financial Performance section of this MD&A, ENMAX Energy was impacted in 2014 by the Keephills Unit 2 outage.

On April 24, 2014, ENMAX Energy signed a purchase and sale agreement with Capital Power Corporation (Capital Power) in support of a joint venture agreement (JVA) to develop, construct, own and operate a natural-gas-fired facility west of Edmonton with a generation capacity of up to 1,050 MW. The proposed facility, Genesee 4 and 5, would be built on a site near Capital Power's existing Genesee facility and is expected to utilize the latest high-efficiency gas-fueled combustion turbine combined cycle technology. ENMAX Energy executed the JVA and associated agreements with Capital Power on July 18, 2014, with similar terms to the Shepard JVA; however, in this case, Capital Power will lead the construction of the project and operate the facility. Subject to a number of project milestones being achieved and other considerations, we expect construction of the proposed facility to be completed between 2018 and 2020, when additional generation will be required to meet the growing demand in Alberta, when some coal-fired generation will be set to retire.

On May 21, 2014, ENMAX Energy executed agreements with Encana Corporation (Encana) to purchase natural gas-fired electricity generation assets at two locations, increasing electricity generation supply by 170 MW. Under the agreements, ENMAX Energy will purchase 100 per cent of Encana's 115 MW gas-fired Cavalier plant, located near Strathmore, Alberta, and Encana's 50 per cent interest in a 110 MW gas-fired plant in Balzac, Alberta, which Encana jointly owns with Nexen Inc. (Nexen). Once the purchase has closed, ENMAX Energy will be the operator of the Cavalier plant and Nexen will remain the operator of the Balzac facility. The purchases are expected to close in the third quarter of 2014, following all regulatory approvals.

At June 30, 2014, nearly 97 per cent of the overall Shepard project work was complete, and approximately $1,297 million of the $1,365 million project budget has been incurred. The project has surpassed 3.8 million hours of construction invested, and on-site safety performance has exceeded our expectations. The project commissioning activities are expected to ramp up in the latter half of 2014 with full commercial operations expected in early 2015.

In accordance with the terms of the Battle River PPA, Battle River Unit 3 and Unit 4 ceased to be part of the PPA at the end of 2013. In January 2014, ENMAX capacity ownership in this PPA was therefore reduced, from 663 MW of capacity ownership to 368 MW, which represents our 100 per cent interest in the output of Battle River Unit 5. Excluding any outages, ENMAX Energy produced or had exclusive access to 1,816 MW of electricity generation to supply customer demand during the six months ended June 30, 2014.

KEY BUSINESS STATISTICS

	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
Market heat rate – flat average (GJ/MWh)	**9.52**	36.77	**10.62**	29.38
Average wholesale market spark spread ($/MWh) [1]	**6.74**	96.53	**12.82**	68.21
Average flat pool price ($/MWh)	**42.30**	123.36	**52.02**	93.74
Average natural gas price ($/GJ)	**4.45**	3.35	**4.90**	3.19
Generation volume (Gigawatt hours [GWh])	**2,455**	2,405	**5,145**	5,229
Electricity sold (GWh)	**4,549**	4,611	**9,512**	9,557
Natural gas sold (terajoules [TJ])	**8,740**	8,228	**31,831**	27,257

(1) Assuming an average combined cycle gas turbine heat rate of 8 GJ per MWh.

In the three and six months ended June 30, 2014, ENMAX Energy experienced a decrease in the market heat rate, average wholesale market spread and average flat pool price from 2013 levels. The decreases are attributed to lower settled power pool prices in the market and the impact of increased natural gas prices due to colder weather in 2014.

ENMAX Energy sold 4,549 Gigawatt hours (GWh) of electricity to customers in the current quarter compared with 4,611 GWh in the same period of 2013. For the six months ended June 30, 2014, ENMAX Energy sold, under contract, 9,512 GWh of electricity to customers, compared with 9,557 GWh in the same period in 2013. This slight decrease is due primarily to a decrease in commercial and residential variable price contract volumes.

ENMAX Energy's natural gas customers purchased 8,740 terajoules (TJ) of natural gas in the second quarter of 2014, compared with 8,228 TJ in the same period in 2013. This increase is due to an increased number of customers. For the six months ended June 30, 2014, ENMAX Energy sold 31,831 TJ of natural gas to customers compared with 27,257 TJ in the same period of 2013. This increase in volumes is due primarily to the impact of cold weather in the first quarter of 2014 and an increased number of customers.

FINANCIAL RESULTS

ENMAX Energy recorded earnings before interest and income taxes (EBIT) of $36.1 million and $72.9 million for the three and six months ended June 30, 2014, respectively, compared with a loss of $5.7 million and earnings of $43.0 million in the same periods in 2013.

EBIT FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2014, COMPARED WITH THE SAME PERIODS IN 2013

(millions of dollars)	Three Months Ended	Six Months Ended
EBIT for the period ended June 30, 2013	(5.7)	43.0
Unusual item included in results:		
Keephills 1 outage 2013	63.5	73.9
Keephills 2 outage 2014	-	(17.4)
Increased (decreased) margins attributable to:		
Electricity, excluding Keephills outage	(20.2)	(25.8)
Natural gas	2.0	1.9
Contractual services and other revenues	0.6	(5.1)
Decreased (increased) expenses:		
OM&A	5.5	9.0
Foreign exchange	(10.1)	(6.6)
Amortization	0.5	-
EBIT for the period ended June 30, 2014	36.1	72.9

There were no unusual outages in the second quarter of 2014 while the Keephills Unit 1 outage had an impact of $63.5 million in the second quarter of 2013. For the six months ended June 30, 2014, Keephills Unit 2 resulted in an unfavourable impact of $17.4 million compared with Keephills Unit 1 impact of $73.9 million in the same period in 2013. See PPA Outages on page 3 of this report for further details.

Normalized electricity margins for the three months ended June 30, 2014, decreased $20.2 million to $98.8 million compared with the $119.0 million recorded in the same three months in 2013. Normalized electricity margins for the six months ended June 30, 2014, decreased $25.8 million to $196.8 million compared with the $222.6 million recorded in the same period of 2013. The decreased margins in the three and six months ended June 30, 2014, were driven primarily by lower prices realized on sales and a decrease in realized gains on hedges. In addition, higher natural gas prices contributed to lower electricity margins as it increased the cost to run our natural gas-fired plants. This was partially offset by higher volumes on commercial and residential fixed price contracts.

Natural gas margins increased $2.0 million to $6.8 million for the three months ended June 30, 2014, compared with $4.8 million in the second quarter of 2013. Natural gas margins increased $1.9 million to $20.6 million for the six months ended June 30, 2014, compared with $18.7 million for the first half of 2013. This increase in the three and six months ended June 30, 2014 is due to higher realized sales price and higher volumes sold. This favourable impact is partially offset by higher cost of natural gas supply.

Contractual services margin and other revenues increased $0.6 million in the three months ended June 30, 2014, to $5.4 million compared to $4.8 million in the same period in 2013. Contractual services margin and other revenues decreased $5.1 million in the six months ended June 30, 2014, to $10.8 million compared to $15.9 million in the six months ended June 30, 2013. The decrease in margins in the six months ended June 30, 2014, was mainly due to the recognition of the recovery of costs associated with ENMAX's joint venture with CPLP in the three months ended March 31, 2013.

OM&A expenses decreased $5.5 million for the three months ended June 30, 2014, to $43.4 million, compared with $48.9 million in same period in 2013. OM&A expenses for the six months ended June 30, 2014, decreased $9.0 million to $84.5 million compared with $93.5 million in the same period in 2013. The decrease in OM&A for the three months and six months ended June 30, 2014, was driven primarily by the higher operating and maintenance costs in the prior year related to the CEC planned outage. In addition, a decrease in advertising costs also contributed to lower OM&A versus the comparative prior period. These decreases were partially offset by an increase in expenses related to billing and collection costs.

For the three months ended June 30, 2014, a net foreign exchange loss of $5.2 million was recognized compared to a gain of $4.9 million in the same period in 2013. For the six months ended June 30, 2014, a foreign exchange loss of $0.1 million was experienced compared to a gain of $6.5 million in the same period of 2013. Foreign exchange gains or losses are primarily the result of realized and unrealized gains or losses on equipment purchases and service agreements denominated in foreign currencies and associated hedges.

Amortization expense for the three months ended June 30, 2014 decreased $0.5 million to $26.3 million, compared with $26.8 million in the second quarter of 2013. Amortization expense for the six months ended June 30, 2014 was $53.3 million, which is consistent with the same period in 2013. The minor decrease in the three months ended June 30, 2014, charge is the result of no new generation assets placed into service compared to prior quarter and general amortization expensed on an existing net book value of assets.

ENMAX POWER

ENMAX Power's highest priority is providing safe, reliable delivery of electricity to Calgarians.

ENMAX Power continues to invest in its electric transmission and distribution system infrastructure to meet Calgary's growing needs. This includes expansion of the distribution system, reinforcement of the transmission system and replacement of aging infrastructure in both systems. Distribution projects include investments in system infrastructure to accommodate residential, commercial and industrial growth, as well as the replacement and modification of existing assets required to meet industry safety and reliability standards. Transmission projects include capacity upgrades to existing substations, new substations and transmission lines to deliver reliable electricity to meet the growing demand within Calgary.

BUSINESS UPDATE

ENMAX Power filed the 2014–2015 Transmission General Tariff Application and 2014 Phase I Distribution Tariff Application with the AUC on July 25, 2013. In this application, we are seeking approval of transmission revenue requirements of $68.1 million and $76.7 million for 2014 and 2015, respectively, and a distribution revenue requirement of $310.9 million for 2014. An oral hearing occurred in July 2014 with the AUC decision expected in the fourth quarter of 2014. A subsequent application is expected to be filed in 2014 that will contain our proposal for our new performance-based rates for future years for our distribution business. Our transmission business is expected to move to a cost of service rate-making model.

As a result of unanticipated accelerated growth in transmission capital expenditures and capital additions during the formula-based rates (FBR) period (2007–2013), the approved FBR formula for transmission operations did not provide a reasonable opportunity to earn our target return on equity (ROE). Using certain "re-opener" provisions approved by the AUC in Decision 2009-035, in 2012 ENMAX Power filed an application seeking approval to recover prior years' earnings shortfalls for capital invested in prior periods. The AUC issued its decision on this application on April 15, 2014. The AUC accepted that the formula required adjustment but modified the proposal that we put forward. A recovery of $13.5 million was recorded in the second quarter of 2014 and a compliance filing has been submitted to the AUC.

We are currently participating in an AUC-initiated generic proceeding for Alberta RRO providers regarding energy price setting plans (EPSPs). The current EPSPs expired June 30, 2014. An oral hearing is expected to be held in September 2014 with a decision rendered in the fourth quarter. The new plans approved by the AUC in this proceeding will set the methodology for calculating the monthly energy rates to be charged to RRO customers for the period after July 1, 2014.

We are also participating in an AUC-initiated generic cost of capital proceeding for all Alberta distribution and transmission utilities. The proceeding will determine the deemed capital structure and allowed ROE for 2013 and 2014. An oral hearing was held in May 2014 with a decision expected at the end of the third quarter.

ENMAX POWER CAPITAL SPENDING

(millions of dollars)	Three Months Ended June 30	Six Months Ended June 30
Alberta Electric System Operator (AESO) required capital projects	6.1	24.8
Asset replacement & modification	34.3	42.5
Residential and non-residential development	15.8	23.7
System infrastructure	7.4	12.6
Information technology, facilities and tools	6.4	9.8
Customer contributions	(16.1)	(23.5)
ENMAX Power capital spending	53.9	89.9

During the six months ended June 30, 2014, we continued to execute our capital plans to meet the increasing need for electricity in Calgary while continuing to offer the same level of reliable service.

KEY BUSINESS STATISTICS

	Three Months Ended June 30		Six Months Ended June 30	
	2014	**2013**	**2014**	**2013**
Electricity sold through the RRO (GWh)	**364**	403	**808**	870
Distribution volumes (GWh)	**2,279**	2,253	**4,742**	4,669
Local access fees collected on behalf of The City ($ millions)	**30.9**	28.3	**66.6**	59.5
SAIDI [(1)]			**0.20**	0.27
SAIFI [(2)]			**0.51**	0.41

(1) SAIDI equals the total duration of a sustained interruption per average customer during a predefined period of time. A sustained interruption is an interruption in duration greater than or equal to one minute.

(2) SAIFI equals how often the average customer experiences a sustained interruption over a predefined period of time. A sustained interruption is an interruption in duration greater than or equal to one minute.

ENMAX Power's regulatory return was determined using a deemed capital structure of 59 per cent debt to 41 per cent equity for the distribution business and 63 per cent debt to 37 per cent equity in the transmission business. ENMAX Power's target ROE was determined by the AUC is 8.75 per cent, and this level of return may either be exceeded or not met based on actual performance by ENMAX Power. An AUC decision regarding the revised deemed capital structure and allowed ROE for 2013 and 2014 is anticipated at the end of the third quarter.

RRO electricity volumes sold decreased to 364 GWh in the three months ended June 30, 2014, compared with 403 GWh in the prior period in 2013. For the six months ended June 30, 2014, RRO electricity volumes sold decreased 62 GWh to 808 GWh compared with 870 GWh in the same period in 2013. Slightly lower demand was seen as a result of a small decrease in customers on the RRO option.

Total electricity delivered in the Calgary service area for the second quarter of 2014, was slightly higher than prior periods. Electricity volumes of 2,279 GWh were delivered during the three months ended June 30, 2014, compared to 2,253 GWh in the same period of 2013. For the six months ended June 30, 2014, total electricity delivered in the Calgary service area increased from the same period in the prior year with electricity volumes delivered of 4,742 GWh compared with 4,669 GWh in the same period in 2013. This modest increase was primarily due to an increase in the number of sites serviced.

FINANCIAL RESULTS

ENMAX Power's financial results are driven by tariffs approved by the AUC for the regulated transmission, distribution and RRO businesses and by earnings from its competitive power services business. The regulated segment accounted for 87 and 88 per cent of ENMAX Power's total revenue in the three and six months ended June 30, 2014, compared with 89 per cent in both periods in 2013.

ENMAX Power recorded EBIT of $33.0 million and $53.3 million for the three and six months ended June 30, 2014, respectively, compared with $11.4 million and $27.1 million in the same periods in 2013.

EBIT FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2014, COMPARED WITH THE SAME PERIODS IN 2013

(millions of dollars)	Three Months Ended	Six Months Ended
EBIT for the period ended June 30, 2013	11.4	27.1
Unusual item included in results:		
2013 Flood response	2.3	2.3
Increased (decreased) margins attributable to:		
Electricity	(0.5)	(0.6)
Transmission and distribution	21.2	34.2
Contractual services and other	4.6	3.7
Decreased (increased) expenses:		
OM&A	(5.4)	(12.0)
Foreign exchange	0.1	-
Amortization	(0.7)	(1.4)
EBIT for the period ended June 30, 2014	**33.0**	**53.3**

Electricity margins from RRO customers decreased $0.5 million to $5.7 million for the three months ended June 30, 2014, compared with $6.2 million in the same period in 2013. For the six months ended June 30, 2014, RRO electricity margins decreased $0.6 million to $11.5 million compared with $12.1 million in the same period in 2013. This decreased margin was primarily the result of higher electricity costs and a decrease in sales volumes as more customers took advantage of competitive offers.

Transmission and distribution margins consist of amounts charged for wire services net of electrical grid charges and local access fees. Transmission and distribution margins increased $21.2 million to $75.0 million for the three months ended June 30, 2014, compared with $53.8 million in the same period in 2013. Transmission and distribution margins increased $34.2 million to $139.9 million for the six months ended June 30, 2014, compared with $105.7 million for the six months ended June 30, 2013. The increased margin in the three and six months ended June 30, 2014, is due primarily to an increase in approved rates and a decision in the second quarter of 2014 approving recovery of earnings on transmission capital invested in prior years. In July 2013, ENMAX submitted a cost of service (COS) filing seeking an increase in the transmission tariff for 2014 and 2015. On October 15, 2013, the AUC approved an interim rate adjustment, representing 60 per cent of the applied for rate increase in the COS filing. AUC's final decision on the rate increase, submitted in the July 2013 COS filing, is

anticipated in the fourth quarter of 2014. On April 15, 2014, ENMAX received a decision from the AUC with respect to an application seeking approval to recover earnings on higher transmission capital expenditures that were necessary to support the needs of the city of Calgary. The impact of this decision is an increase to margins of $13.5 million for the three and six months ended June 30, 2014. For the three months ended June 30, 2014, margins for contractual services and other revenues increased $4.6 million to $8.3 million compared with $3.7 million during the same period in 2013. For the six months ended June 30, 2014, margins for contractual services and other increased $3.7 million to $14.0 million compared with $10.3 million for the six months ended June 30, 2013. The increase in margins for the three and six months ended June 30, 2014, is mainly due to increased activity on residential and commercial developer work in the second quarter as weather conditions improve from first quarter of 2014 and the progression of the Tuscany-Rockyridge LRT expansion project with a scheduled completion date later in 2014.

Normalized OM&A expenses for the three and six months ended June 30, 2014, totalled $40.1 million and $82.6 million, respectively, compared with $34.7 million and $70.6 million, respectively, in the same periods in 2013. The increase in OM&A costs for the three and six months ended June 30, 2014, was driven primarily by higher staff costs as a result of annual staff compensation adjustments and additional employees to support the growth of Calgary's electrical system.

Amortization for the three and six months ended June 30, 2014, totalled $16.0 million and $29.5 million, respectively, compared with $15.3 million and $28.1 million, respectively, in the same periods in 2013. The increase was the net result of amortization related to new assets put into service and was partially offset by a decrease in the asset base from older assets concluding their depreciable lives.

CORPORATE AND INTERSEGMENT ELIMINATIONS

ENMAX Corporate provides billing and customer care services, shared services and financing to ENMAX Power and ENMAX Energy. During the three and six months ended June 30, 2014, EBIT for ENMAX Corporate increased slightly to $1.1 million and $2.4 million, respectively, as compared with $1.0 million and $1.6 million, respectively, in the same periods in 2013.

SELECTED QUARTERLY FINANCIAL DATA

	2014			2013			2012	
(millions of dollars)	Second	First	Fourth	Third	Second [2]	First	Fourth	Third
Total revenue	**767.4**	1,002.5	897.1	803.7	872.6	843.4	882.9	810.0
Operating margin [1]	**200.9**	177.2	232.5	150.0	128.9	180.6	208.0	151.5
EBIT [1]	**70.2**	58.4	102.7	30.1	6.7	65.0	77.4	41.7
Net earnings	**63.6**	35.9	88.3	20.7	185.2	58.3	63.9	45.4

(1) Non-GAAP financial measure. See discussion that follows in the MD&A.

(2) The sale of Envision occurred in the second quarter of 2013; gain of $175.9 million recorded in the quarter.

Many variables must be considered regarding the seasonality of revenues, operating margin, EBIT and net earnings. In the first half of 2014, revenues increased as a result of higher natural gas sales due to increased demand and prices. The decreased net earnings during the first quarter reflect the $20.7 million of settlement costs associated with the termination of interest rate swaps. Overall, the majority of the business does not experience extreme cyclical activities that would allow identification of common variations quarter over quarter.

Electricity volumes sold and electricity volumes distributed to industrial and institutional customers are not significantly seasonal in nature. While customers can have seasonal requirements, the seasonal requirements of one customer base can be offset by another, resulting in relatively flat demand over the course of a year. Overall volumes are predominantly cyclical on a 24-hour period; however, residential volumes sold and distributed peak in the winter, with a higher demand for heat, resulting in higher revenues during winter months. Volume requirements of commercial customers peak in the summer, with higher demand for air conditioning. This is offset by a lower demand in the residential market during the summer. Over longer periods of time, volumes can fluctuate with general economic activity and population growth. Unusual items and events may have an impact on seasonal expectations.

Natural gas volumes and prices are correlated seasonally as a result of weather patterns. Natural gas consumption and prices will increase with extreme weather typically seen in the winter. As well, natural gas prices can rise in extreme hot weather in the summer as peak electricity demand results in increased gas-fired generation. Revenue levels tend to decline in the fall and spring due to unfavourable trends in natural gas prices and volumes during those parts of the calendar year.

NON-GAAP FINANCIAL MEASURES

The Corporation provides non-GAAP financial measures in the MD&A. These measures do not have any standard meaning prescribed by GAAP and may not be comparable to similar measures presented by other companies. The purpose of these financial measures and their reconciliation to GAAP financial measures are shown below. These non-GAAP measures are consistent with the measures used in the previous year, with the exception of removal of the unusual items in the operating margin measure.

OPERATING MARGIN

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2014**	**2013**	**2014**	**2013**
Electricity margins	**104.0**	124.8	**207.6**	234.0
Natural gas margins	**6.7**	4.7	**20.0**	18.3
Transmission and distribution margins	**75.0**	53.8	**139.9**	105.7
Contractual services margins [1] and other revenue	**15.2**	9.1	**28.0**	25.4
Operating margin (non-GAAP financial measure), excluding unusual items	**200.9**	192.4	**395.5**	383.4
Deduct:				
Unusual item: Outage at Keephills Unit 1	**-**	63.5	**-**	73.9
Unusual item: Outage at Keephills Unit 2	**-**	-	**17.4**	-
Unusual item: Flood response	**-**	2.3	**-**	2.3
OM&A, foreign exchange, amortization, interest and income taxes	**137.3**	118.4	**278.6**	243.9
Net earnings from continuing operations (GAAP financial measure)	**63.6**	8.2	**99.5**	63.3

(1) Contractual services margins include earnings from distributed generation; meter reading and data management services for non-Calgary municipalities; water meter reading; pole and duct rentals; service locates; streetlight repairs; LRT monitoring; mapping record management; engineering, procurement, construction and maintenance services; utility trenching; construction and maintenance of LRT systems; self-retailing services; and billing services.

Operating margin is a useful measure of business performance, as changes in the market price of electricity and natural gas purchased for resale affect revenue and cost of sales equally. ENMAX Energy's strategy links the cost of supply to longer-term demand contracts, which results in relatively stable margins even during times of volatile wholesale prices and revenue levels. Therefore, operating margins better reflect profitability than revenue levels alone.

EBITDA

(millions of dollars)	Three Months Ended June 30 2014	Three Months Ended June 30 2013	Six Months Ended June 30 2014	Six Months Ended June 30 2013
Adjusted EBITDA (non-GAAP financial measure)	113.2	227.3	213.4	337.0
Deduct: EBITDA from discontinued operations	-	(177.6)	-	(182.1)
Standardized EBITDA (non-GAAP financial measure)	113.2	49.7	213.4	154.9
Deduct:				
Amortization	43.0	43.0	84.8	83.2
Interest	5.3	6.3	33.0	13.1
Income taxes (recovery) expense	1.3	(7.8)	(3.9)	(4.7)
Net earnings from continuing operations (GAAP financial measure)	63.6	8.2	99.5	63.3

Earnings before interest, income tax, depreciation and amortization (EBITDA) is a useful measure of business performance, as it provides an indication of the cash flow results generated by primary business activities without consideration as to how those activities are financed and amortized, or how the results are taxed in various business jurisdictions. EBITDA is also used to evaluate certain debt coverage ratios.

EBIT

(millions of dollars)	Three Months Ended June 30 2014	Three Months Ended June 30 2013	Six Months Ended June 30 2014	Six Months Ended June 30 2013
EBIT (non-GAAP financial measure)	70.2	6.7	128.6	71.7
Deduct:				
Interest	5.3	6.3	33.0	13.1
Income tax (recovery) expense	1.3	(7.8)	(3.9)	(4.7)
Net earnings from continuing operations (GAAP financial measure)	63.6	8.2	99.5	63.3

EBIT is a useful measure of business performance, as it provides an indication of the operating results generated by primary business activities, including the costs of amortization. It does not consider how those activities are financed or how the results are taxed in various business jurisdictions.

FUNDS GENERATED FROM OPERATIONS

(millions of dollars)	Three Months Ended June 30 2014	Three Months Ended June 30 2013	Six Months Ended June 30 2014	Six Months Ended June 30 2013
Funds generated from operations (non-GAAP financial measure)	109.2	28.4	207.2	124.9
Changes in non-cash working capital	57.3	(131.3)	23.2	(140.9)
Employee future benefits	(1.0)	(3.2)	(0.7)	(1.3)
Cash flow from continuing operations	165.5	(106.1)	229.7	(17.3)
Cash flow from assets held for sale	-	7.8	-	(4.0)
Cash provided by operating activities (GAAP financial measure)	165.5	(98.3)	229.7	(21.3)

Funds generated from operations are used as an additional metric of cash flow without regard to changes in our non-cash working capital.

TOTAL INTEREST COST

(millions of dollars)	Three Months Ended June 30 2014	Three Months Ended June 30 2013	Six Months Ended June 30 2014	Six Months Ended June 30 2013
Total interest cost (non-GAAP financial measure)	15.3	21.4	33.3	42.5
Capitalized interest	(11.2)	(15.5)	(23.1)	(30.5)
Other non-interest financing costs	1.2	1.0	2.1	2.1
Interest expense, excluding swaps settlement	5.3	6.9	12.3	14.1
Interest rate swaps settlement	-	-	20.7	-
Ineffective portion of interest rate swaps	-	(0.6)	-	(1.0)
Interest expense (GAAP financial measure)	5.3	6.3	33.0	13.1

Total interest cost is used in determining interest coverage ratios.

FINANCIAL CONDITION

SIGNIFICANT CHANGES IN THE CORPORATION'S FINANCIAL CONDITION

(millions of dollars, except % change)	June 30, 2014	December 31, 2013	$ Change	% Change	Explanation for Change
ASSETS					
Accounts receivables	560.0	665.5	(105.5)	(16%)	Decrease due to timing of receipts, decreased electricity sales prices and collection of AUC decision rates.
Property, plant and equipment	3,132.4	3,022.6	109.8	4%	Capital expenditures, net of retirements, dispositions and amortization.
PPAs	343.1	369.5	(26.4)	(7%)	Amortization of PPAs.
LIABILITIES AND SHAREHOLDER'S EQUITY					
Accounts payable and accrued liabilities	363.0	436.8	(73.8)	(17%)	Decrease driven by lower capital accruals, decrease in electricity prices and timing of payments.
Other assets/liabilities [1] [2]	(20.8)	13.9	34.7	(250%)	Change in fair value of hedging instruments and settlement of interest rate swaps.
Dividend payable	30.0	-	30.0	100%	Dividend declared in March to be paid in quarterly payments over the course of the year.

(1) Net asset and liability positions.
(2) Includes current and long-term amounts.

LIQUIDITY AND CAPITAL RESOURCES

SHARE CAPITAL

As at June 30, 2014 and 2013 *(millions of dollars, except share amounts)*	Number of Shares	Amount
Authorized:		
Unlimited number of common shares		
Issued and outstanding:		
Issued on incorporation (one dollar)	1	–
Issued on transfer of net assets from Calgary Electric System (CES)	1	278.2
Issued on transfer of billing and customer care assets from The City in 2001	1	1.9
	3	**280.1**

CAPITALIZATION

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
Long-term debt [1]	**1,442.6**	1,439.0
Shareholder's equity		
Share capital	**280.1**	280.1
Retained earnings	**2,225.9**	2,186.4
Accumulated other comprehensive income (loss)	**10.8**	(6.3)
Total shareholder's equity	**2,516.8**	2,460.2
Total capitalization (long-term debt plus shareholder's equity)	**3,959.4**	3,899.2

(1) Includes the current portion of long-term debt of $61.5 million (December 31, 2013—$63.7 million). Maturity dates range from May 2015 to June 2039.

TOTAL LIQUIDITY AND CAPITAL RESERVES

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
Committed and available bank credit facilities	**1,150.0**	1,150.0
Letters of credit issued:		
Power pool purchases	**85.4**	85.2
Energy trading	**32.5**	34.5
Regulatory commitments	**104.0**	105.9
Asset commitments	**3.2**	3.1
PPAs	**56.7**	75.2
	281.8	303.9
Remaining available bank facilities	**868.2**	846.1
Cash on hand	**76.4**	80.6
Total liquidity and capital reserves	**944.6**	926.7

The increase in total liquidity and capital reserves during for the six months ended June 30, 2014, is attributed primarily to the decrease in PPAs subsequent to Battle River Units 3 and 4 capacity ownership reverting back to ATCO Power on January 1, 2014, in accordance with the terms of the Battle River PPA.

LONG-TERM DEBT

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
Long-term debt [1] consisting of:		
Alberta Capital Finance Authority (ACFA) debentures, with remaining terms of:		
Less than 5 years	74.3	34.0
5–10 years	91.3	122.4
11–15 years	22.3	14.4
16–20 years	274.4	187.1
21–25 years	657.5	557.6
Private debentures		
Series 1, remaining term of 4 years, bullet maturity on June 19, 2018	298.3	298.2
Non-recourse term financing, with remaining term of 2.5 years	19.9	220.5
Promissory note, remaining term of 12.5 years	4.6	4.8
	1,442.6	1,439.0

(1) Includes current portion of long-term debt of $61.5 million (December 31, 2013— $63.7 million). Maturity dates range from May 2015 to June 2039.

CONTRACTUAL OBLIGATIONS WHICH MAY IMPACT THE CORPORATION'S FINANCIAL CONDITION

As at June 30, 2014 *(millions of dollars)*	Total	Less than 1 year	1–3 years	4–5 years	After 5 years
Total debt [1]	1,442.6	61.5	136.4	414.2	830.5
Operating leases	50.0	7.0	12.4	9.1	21.5
Purchase obligations [2]	114.4	72.1	19.4	12.0	10.9
Asset retirement obligations	15.6	-	-	-	15.6
Other long-term obligations [3]	25.1	-	13.6	4.6	6.9
Total contractual obligations	**1,647.7**	**140.6**	**181.8**	**439.9**	**885.4**

(1) Total debt includes short-term debt and excludes interest payments.

(2) Purchase obligations means an agreement to purchase goods or services that is enforceable and legally binding on ENMAX that specifies all significant terms, including fixed or minimum quantities
to be purchased; fixed, minimum, or variable price provisions; and the approximate timing of the transaction.

(3) Other long-term obligations means other long-term liabilities reflected on the Corporation's balance sheet.

CAPITAL STRATEGY

CREDIT METRICS

As at	June 30, 2014	December 31, 2013
Long-term debt to total capitalization [1]	**36.4%**	35.3%
Debt to EBITDA [2]	**3.4X**	2.6X
EBITDA to total interest [3]	**5.2X**	6.1X

(1) As at year end, long-term debt (including current portion) to total capitalization is equal to long-term debt divided by total long-term debt plus shareholder's equity. If cash were netted against the debt, the ratio as at June 30, 2014, would be 34.5 per cent (December 31, 2013 — 33.3 per cent).

(2) Debt to EBITDA is equal to long-term debt (including current portion) divided by EBITDA for the last 12-month rolling period. If cash were netted against the debt, the ratio as at June 30, 2014, would be 3.2X (December 31, 2013 — 2.5X).

(3) EBITDA to total interest is equal to EBITDA for the last 12-month rolling period divided by total interest cost (non-GAAP financial measures) calculated on a 12-month rolling basis.

The business is funded with a view to maintaining a conservative capital structure in line with our strategy of maintaining a stable, investment grade credit rating. We have set long-term target ratios for long-term debt to total capitalization at a maximum of 45 per cent, a debt to EBITDA ratio at a maximum of 3.5 times and an EBITDA to total interest coverage ratio at five times or better. Very low electricity prices, asset outages, and high capital expenditures associated with significant construction projects or other factors could result in targets not being reached for short periods of time. Targets are managed using a long-term view and are set at more conservative levels than actual debt covenants. Standard & Poor's has assigned ENMAX a BBB+ rating with a stable outlook. Dominion Bond Rating Services has assigned a credit rating of A (low). These ratings provide reasonable access to debt capital markets.

The principal financial covenant in our credit facilities is debt to capitalization. As at June 30, 2014, we are non-compliant with a financial covenant for Kettles Hill related to non-recourse financing classified as long-term debt on the balance sheet. The carrying amount of the debt as at June 30, 2014, is $19.9 million.

CASH PROVIDED BY OPERATING ACTIVITIES

Funds generated from operations for the three and six months ended June 30, 2014, were $109.2 million and $207.2 million, respectively, compared with $28.4 million and $124.9 million, respectively, in the same periods in 2013. The increased funds generated period-over-period were primarily due to positive change in unrealized market value of financial contracts due to settlement of interest rate swaps being realized and higher cash generating earnings from continuing operations.

Cash provided by operating activities for the three months ended June 30, 2014, was $165.5 million compared to a negative $98.3 million in the same period in 2013. For the six months ended June 30, 2014, cash provided by operations increased to $229.7 million from negative $21.3 million in the same period in 2013. The increase was driven by the decrease of accounts receivable (which was lower due to timing of payments and collection of AUC decision rates) and higher cash generating earnings from continuing operations in 2014. This was partially offset by reduction of accounts payable (which was lower due to timing of payments to the AESO).

INVESTING ACTIVITIES

Capital additions were $95.1 million and $171.6 million, respectively, in the three and six months ended June 30, 2014, compared to $118.3 million and $230.1 million, respectively, in the same period in 2013, which included $16.5 million and $33.2 million, respectively, of spending in assets held for sale. Capital projects for the three and six months ended June 30, 2014, included $50.5 million and $87.9 million, respectively, related to investment in the transmission and distribution network in Calgary and surrounding area; $38.6 million and 74.0 million in construction costs related to Calgary area generation projects; and $6.0 million and $9.7 million related to other capital additions, including information technology development.

Continued investment in information technology will allow ENMAX to comply with regulations and effectively operate the business, in line with the Corporation's strategy to maintain the reliability and cost effectiveness of its technology infrastructure while meeting the challenges of obsolescence and growth.

FINANCING ACTIVITIES

On March 17, 2014, ENMAX repaid $200.6 million of non-recourse term financing and $35.6 million of a fixed-for-floating interest rate swap related to CEC prior to maturity on September 2026. In addition, we settled back-to-back swaps that were initially executed as a hedging relationship in relation to the fixed-for-floating swap. Settlement costs of $20.7 million associated with the termination of the interest rate swaps were recorded as interest expense.

We made regularly scheduled long-term debt principal payments of $20.9 million and $27.7 million, respectively, during the three and six months ended June 30, 2014, compared with $19.8 million and $28.5 million, respectively, in the same period in 2013.

At June 30, 2014, cash and cash equivalents amounted to $76.4 million compared with $80.6 million at December 31, 2013. At June 30, 2014, no commercial paper was outstanding consistent with December 31, 2013, and there were no overdrafts on bank accounts, which is also consistent with December 31, 2013.

On March 5, 2014, a dividend of $60.0 million was declared payable to The City of Calgary (The City) in quarterly installments throughout 2014. The first two quarterly instalments of the dividend have been paid, and the remaining instalments will be paid during the balance of 2014.

On June 15, 2014, we obtained $232.1 million of 5-, 10-, 20- and 25-year debentures from The City through arrangements with the Alberta Capital Finance Authority (ACFA) (2013 – $140.6 million 5-, 10-, 20- and 25-year debentures) to fund ongoing investment relating to regulated transmission and distribution network in Calgary and the surrounding area.

Subsequent to June 30, 2014, on July 11, 2014, our unsecured credit facilities were amended. The total unsecured credit facilities remain at $1,150.0 million, with $900.0 million in bilateral credit facilities and $250.0 million of syndicated credit facilities. The Letter of Credit tranches were increased from $300.0 million to $375.0 million capacity and extended by one year to July 20, 2017. Additionally, the $775 million operating tranches were extended by two years to July 20, 2019.

FUTURE ACCOUNTING CHANGES

On February 13, 2008, the AcSB confirmed the changeover from GAAP to IFRS, as issued by the International Accounting Standards Board (IASB), would be effective for fiscal years beginning on or after January 1, 2011. The AcSB has issued amendments to this directive that presently allows entities that have activities subject to rate regulation to delay adoption of IFRS until January 1, 2015. As such, ENMAX will be required to adopt IFRS in reporting interim and annual consolidated financial statements, including comparative periods, beginning January 1, 2015. Even though IFRS uses a conceptual framework similar to GAAP, there will be differences in accounting policies.

With the initial decision to adopt IFRS in Canada, we executed a conversion plan for the Corporation and have since maintained a state of readiness. Certain updates and activities will be required to prepare for the final adoption of IFRS in 2015.

AREA	DESCRIPTION OF CHANGE	STATUS AND SIGNIFICANT IMPACTS
Standards Update	A number of new standards and amendments to standards have been issued since we last prepared our transition plan.	These standards have been evaluated for their applicability and impact. We continue to monitor IASB activities and develop reporting requirements to meet new standards.
Opening Balance Sheet	Our opening balance sheet date is January 1, 2014.	Adjustments identified previously are being updated with current information. Our auditors have been engaged to review these adjustments.
Rate Regulated Activities	On January 30, 2014, the IASB issued the interim standard IFRS 14 Regulatory Deferral Accounts to address accounting for effects of rate regulation under IFRS.	This standard has being evaluated. There will be changes to disclosures and classifications of regulatory balances under IFRS.
Systems	The original system solution is no longer valid given our move to a new project costing and fixed asset system on January 1, 2014.	The requirements of IFRS were built into the new project costing and fixed asset system. Testing and evaluation of this system, for use in IFRS reporting, is underway.
Internal Control over Financial Reporting (ICFR) and Disclosure Controls	Changes to our control environment cannot be finalized until IFRS standards and Corporation policies are finalized.	We continue to evaluate the impacts of IFRS changes on disclosure controls and ICFR. Open discussions continue with our external auditor about possible outcomes of the new standards.
Financial Reporting Expertise	Internal resources are being utilized for conversion efforts.	Conversion status is provided to the Audit, Finance and Risk Committee on a quarterly basis. Training efforts are being reintroduced.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of our consolidated financial statements requires the use of estimates and assumptions. Accounting policies have been developed to ensure appropriate implementation and interpretation of accounting rules, and complex situations are addressed using careful judgment and research. Adjustments to previous estimates that impact net income are recorded in the period they become known.

Our critical accounting estimates are related to revenue recognition, allowance for doubtful accounts, amortization expense, asset impairment, asset retirement obligations, provisions for income taxes, employee future benefits, financial instruments and interest during construction. The estimates and assumptions made in these areas can be highly uncertain at the time the estimate or assumption is made. Different or changing estimates and assumptions could potentially have a material impact on our financial position or results of operations. These critical estimates are described in our 2013 Financial Report in the Critical Accounting Estimates section of the MD&A and in Note 2 of the Consolidated Financial Statements.

The presentation of our revenues, margins and OM&A both in the current period and comparative periods have been adjusted to include billing recoveries related to electricity, natural gas and penalty revenues that were previously netted against OM&A expense. To illustrate the impact of reclassification for the three-month period ended June 30, 2013, the reclassification adjustment resulted in an increase in electricty revenue of $9.0 million, natural gas revenue of $2.2 million, other revenue of $1.9 million, electricity costs of $0.1 million and OM&A of $13.1 million. The reclassification for the six-month period ended June 30, 2013, was an increase in electricity revenue of $17.6 million, natural gas revenue of $4.2 million, other revenue of $4.6 million, electricity costs of $0.2 million and OM&A of $26.1 million. This presentation change does not impact net earnings. The change in presentation has been applied to the comparative periods presented.

RISK MANAGEMENT AND UNCERTAINTIES

Our approach to risk management addresses risk exposures across all of the Corporation's business activities and risk types. We utilize an enterprise risk management (ERM) program to identify, analyze, evaluate, treat and communicate the Corporation's risk exposures in a manner consistent with our business objectives and risk tolerance.

Risk exposures are managed within levels approved by the Board and senior management and are monitored by personnel in the business units, the risk management department and the senior management team. At a management level, each accountability area is responsible for assessing its risk exposures and implementing risk mitigation plans. Our risk management department coordinates an enterprise risk assessment process and provides risk reporting and related monitoring. Risk oversight is delivered through the Board and the Risk Management Committee (RMC), which consists of senior management members. Together, the RMC and Board oversee identified risk exposures and risk management programs, including the ERM program. For further information on risks, refer to the Risk Management and Uncertainties section of the MD&A contained in our 2013 Financial Report.

FINANCIAL INSTRUMENTS

In conducting our operations, we use various instruments, including forwards, futures, swaps and options to reduce our market risks.

ENERGY TRADING DERIVATIVES

Energy trading derivatives are contracts-for-differences that are financial forwards and futures for electricity and gas positions. This does not include electricity and gas contracts that are not considered to be accounting derivatives (normal purchase and sale contracts). The fair value of ENMAX Energy's contracts-for-differences is determined by estimating the amounts that would have to be received or paid to counterparties to terminate the contracts at June 30, 2014, and December 31, 2013.

OUTSTANDING CONTRACTS-FOR-DIFFERENCES

As at	June 30, 2014	December 31, 2013
Notional quantities:		
Electricity sales (GWh)	4,709	3,958
Natural gas sales (TJ)	980	670
Electricity purchases (GWh)	4,461	6,185
Natural gas purchases (TJ)	45,006	19,615

At June 30, 2014, on the basis of electricity and natural gas prices at that date, the fair market value of these contracts amounted to an unrealized positive mark-to-market adjustment of $7.5 million as compared to negative mark-to-market adjustment of $3.2 million as at December 31, 2013. This amount does not reflect the fact that these contracts will settle at prices in effect in the future.

Refer to Note 2 in the Notes to the Consolidated Financial Statements for further information on financial instruments.

ASSET RETIREMENT OBLIGATIONS

At June 30, 2014, asset retirement obligations exist relating to the following generating assets: McBride, Taber, Kettles, Crossfield and CEC. The accretion expense on these assets is included in OM&A in the Consolidated Statements of Earnings and Comprehensive Income.

EXPECTED REMEDIATION LIABILITY AND TIMING FOR EACH ASSET

(millions of dollars)	Date	Amount
McBride	September 2057	47.8
Taber	December 2057	32.4
Kettles	May 2071	26.2
Crossfield	December 2048	10.4
CEC	March 2043	29.6

TRANSACTIONS WITH RELATED PARTIES

Our related-party transactions comprise both revenues from and expenditures to The City. The City is the sole shareholder of ENMAX. Total revenues received from The City for the three and six months ended June 30, 2014, were $24.9 million and $65.5 million, respectively (2013—$24.8 million and $62.5 million). The significant components include contract sales of electricity, construction of infrastructure, provision of non-regulated power distribution services and billing and customer care services relating to The City's utilities departments. We have committed to a water supply agreement with The City, to commence upon completion of Shepard, whereby The City will supply a specified amount of water annually to facilitate Shepard operations.

As at June 30, 2014, amounts owing to us from The City for services provided were $25.0 million (December 31, 2013—$31.2 million).

Total expenditures for goods and services provided by The City for the three and six months ended June 30, 2014, were $31.9 million and $68.9 million, respectively (2013—$29.5 million and $63.5 million). Most of these expenditures were for local access fees for use of The City's rights-of-way, the cost of which is passed directly to transmission and distribution customers.

Transactions between ENMAX and The City have been recorded at the exchange amounts. Exchange amounts are the amounts outlined by the contracts in effect between us and The City. The measurement basis used in determining the above values is the contract amount that is considered fair market value; that is, the measurement basis is likely the same as would be used for a third-party arm's-length transaction.

We borrow from The City through arrangements with the ACFA to fund ongoing investment only relating to the regulated transmission and distribution network in Calgary and the surrounding area. The total amount of debt owed to The City was $1,119.8 million at June 30, 2014 (December 31, 2013—$915.5 million). Interest paid on this debt for the three and six months ended June 30, 2014, was $16.4 million and $18.9 million, respectively (2013—$15.0 million and $17.8 million). We are required to reimburse The City for all principal and interest payments with respect to this debt on the same days as The City disburses the payments to the debt holders. In addition, we are required to pay a loan management fee to The City of 0.25 per cent on the average monthly outstanding debenture balance held by The City on behalf of ENMAX. The administration fee paid for the three and six months ended June 30, 2014, was $0.6 million and $1.2 million, respectively (2013—$0.5 million and $1.0 million).

Additional details on our transactions with The City can be found in Note 16 in the Notes to the Consolidated Financial Statements.

OUTLOOK

The discussion in this section is qualified by the caution to readers at the beginning of the report. The financial results forecasted for 2014 are based on certain assumptions about factors that are outside of the control of the Corporation or management. Actual results that differ from these assumptions could have a significant impact on expected results. The key assumptions that could significantly impact forecast earnings are commodity prices, residential and small business volumes, unplanned outages at generating facilities, settlement of contingencies, regulatory changes and project execution on the Corporation's significant capital projects.

The market price outlook for electricity in 2014 is expected to be lower than 2013 with a return to more historical plant outage rates across the Alberta fleet of generation assets and an increase in supply to the Alberta market. Sources of increased supply include TransAlta's coal-fired plants Sundance 1 & 2 (560 MW), which returned to service in 2013 and a southern Alberta wind farm going online in mid-2014 (300 MW). Further, Shepard (800 MW) will start testing (commissioning) activities in late 2014 with full commercial operations expected in 2015. We have experienced higher natural gas prices thus far in 2014, and we expect them to remain at levels higher than 2013. Spark spreads are expected to be lower due to higher natural gas prices and lower electricity prices. The expected financial results for 2014 will also reflect the impact of the expiration of capacity ownership of the Battle River units 3 and 4 under the PPA, which is partially offset by the lower impact of unplanned outages and replacement power purchases. The volume contracted in each of our customer segments will be a function of availability for contracting and profitability, including alignment with the supply portfolio. With respect to our regulated business, we are awaiting decisions from the AUC, which will have an impact on our earnings.

Management has set significant targets for margin improvement and continuously reviews operations for cost-control opportunities across the Corporation. While aggressive, we have plans to achieve these improvements and are committed to meeting these targets. Overall, profitability in 2014 is expected to be close to 2013 profitability from continuing operations (before the 2013 gain on sale).

CONSOLIDATED FINANCIAL STATEMENTS

CONTENTS

CONSOLIDATED BALANCE SHEETS

AS AT *(millions of dollars)*	June 30, 2014 (unaudited)	December 31, 2013
ASSETS		
Cash and cash equivalents	$ 76.4	$ 80.6
Accounts receivable (Notes 2 and 4)	560.0	665.5
Income taxes receivable	101.1	96.9
Future income tax asset	6.1	8.7
Other current assets (Notes 2 and 5)	70.1	42.6
	813.7	894.3
Property, plant and equipment (Note 6)	3,132.4	3,022.6
Power purchase arrangements	343.1	369.5
Intangible assets	127.5	124.3
Goodwill	16.0	16.0
Employee future benefits (Note 7)	23.5	22.8
Future income tax asset	44.0	59.0
Other long-term assets (Notes 2 and 5)	36.6	57.0
TOTAL ASSETS	$ 4,536.8	$ 4,565.5
LIABILITIES		
Accounts payable and accrued liabilities (Notes 2 and 4)	$ 363.0	$ 436.8
Dividend payable	30.0	–
Future income tax liability	0.1	0.5
Current portion of long-term debt (Note 2)	61.5	63.7
Other current liabilities (Notes 2 and 5)	55.5	52.8
	510.1	553.8
Long-term debt (Notes 2 and 3)	1,381.1	1,375.3
Future income tax liability	82.8	100.1
Other long-term liabilities (Notes 2 and 5)	30.4	60.7
Asset retirement obligations	15.6	15.4
	2,020.0	2,105.3
SHAREHOLDER'S EQUITY		
Share capital	280.1	280.1
Retained earnings	2,225.9	2,186.4
Accumulated other comprehensive income (loss) (Note 9)	10.8	(6.3)
	2,516.8	2,460.2
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 4,536.8	$ 4,565.5

Commitments and contingencies (Note 10)
See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

(unaudited) *(millions of dollars)*	THREE MONTHS ENDED JUNE 30 2014	THREE MONTHS ENDED JUNE 30 2013	SIX MONTHS ENDED JUNE 30 2014	SIX MONTHS ENDED JUNE 30 2013
REVENUE (Note 11)				
Electricity	$ 502.2	$ 675.1	1,119.8	$ 1,242.6
Natural gas	100.5	71.7	331.4	208.9
Transmission and distribution	100.4	74.7	192.4	151.5
Local access fees	30.9	28.3	66.6	59.5
Contractual services	29.7	18.6	51.2	38.9
Other	3.7	4.2	8.5	14.6
TOTAL REVENUE	767.4	872.6	1,769.9	1,716.0
COST OF SERVICES PROVIDED (Note 11)				
Electricity	398.2	613.8	929.6	1,082.5
Natural gas	93.8	67.0	311.4	190.6
Transmission and distribution	25.4	20.9	52.5	45.8
Local access fees	30.9	28.3	66.6	59.5
Contractual services	18.2	13.7	31.7	28.1
Operations, maintenance and administration	82.6	84.1	164.5	161.1
Foreign exchange loss (gain)	5.1	(4.9)	0.2	(6.5)
TOTAL COST OF SERVICES PROVIDED	654.2	822.9	1,556.5	1,561.1
EARNINGS BEFORE AMORTIZATION, INTEREST AND INCOME TAXES	113.2	49.7	213.4	154.9
Amortization	43.0	43.0	84.8	83.2
Interest (Note 3)	5.3	6.3	33.0	13.1
Current income tax expense	0.6	11.9	1.5	12.6
Future income tax expense (recovery)	0.7	(19.7)	(5.4)	(17.3)
NET EARNINGS FROM CONTINUING OPERATIONS	63.6	8.2	99.5	63.3
Net earnings from discontinued operations, net of tax	-	1.1	-	4.3
Gain on sale of subsidiary	-	175.9	-	175.9
NET EARNINGS	63.6	185.2	99.5	243.5
OTHER COMPREHENSIVE INCOME, NET OF TAX				
Unrealized gains on available-for-sale financial assets arising during the period, includes future income tax expense of $nil for the three- and six-month periods (2013—$nil tax expense)	0.1	-	0.1	-
Unrealized gains on derivatives designated as cash flow hedges, includes future income tax expense of $4.5 and $9.1 for the three- and six-month periods, respectively (2013—$9.3 and $9.9 tax expense)	7.8	27.0	35.5	28.8
Realized (gains) losses on derivatives designated as cash flow hedges in prior periods transferred to net earnings in current year, includes future income tax expense of $3.1 and $4.5 for the three- and six-month periods, respectively (2013—$5.4 and $ 5.3 tax expense)	(10.2)	(15.0)	(18.5)	(12.0)
Other comprehensive income, net of tax	(2.3)	12.0	17.1	16.8
COMPREHENSIVE INCOME	$ 61.3	$ 197.2	$ 116.6	$ 260.3

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY

(unaudited) *(millions of dollars)*	Share Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total
BALANCE, JANUARY 1, 2013	$ 280.1	$ 1,901.4	$ (19.6)	$ 2,161.9
Net earnings	–	58.3	–	58.3
Dividends	–	(67.5)	–	(67.5)
Other comprehensive income including future tax expense of $0.7	–	–	4.8	4.8
BALANCE, MARCH 31, 2013	$ 280.1	$ 1,892.2	$ (14.8)	$ 2,157.5
Net earnings	–	185.2	–	185.2
Other comprehensive income including future tax expense of $3.9	–	–	12.0	12.0
BALANCE, JUNE 30, 2013	$ 280.1	$ 2,077.4	$ (2.8)	$ 2,354.7
Comprehensive income for the remainder of 2013	–	109.0	(3.5)	105.5
BALANCE, DECEMBER 31, 2013	$ 280.1	$ 2,186.4	$ (6.3)	$ 2,460.2
Net earnings	–	35.9	–	35.9
Dividends	–	(60.0)	–	(60.0)
Other comprehensive income including future tax expense of $3.2	–	–	19.4	19.4
BALANCE, MARCH 31, 2014	$ 280.1	$ 2,162.3	$ 13.1	$ 2,455.5
Net earnings	–	63.6	–	63.6
Other comprehensive income including future tax expense of $1.4	–	–	(2.3)	(2.3)
BALANCE, JUNE 30, 2014	**$ 280.1**	**$ 2,225.9**	**$ 10.8**	**$ 2,516.8**

See accompanying Notes to Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)	THREE MONTHS ENDED JUNE 30,		SIX MONTHS ENDED JUNE 30,	
(millions of dollars)	2014	2013	2014	2013
CASH PROVIDED BY (USED IN):				
OPERATING ACTIVITIES				
Net earnings	$ 63.6	$ 185.2	$ 99.5	$ 243.5
Net earnings from discontinued operations	-	(1.1)	-	(4.3)
Gain on sale of subsidiary	-	(175.9)	-	(175.9)
Items not involving cash (Note 12)	45.6	20.2	107.7	61.6
	109.2	28.4	207.2	124.9
Change in non-cash working capital (Note 13)	57.3	(131.3)	23.2	(140.9)
Employee future benefits	(1.0)	(3.2)	(0.7)	(1.3)
Cash flow from continuing operating activities	165.5	106.1	229.7	(17.3)
Cash flow from discontinued operations	-	7.8	-	(4.0)
	165.5	(98.3)	229.7	(21.3)
INVESTING ACTIVITIES				
Purchase of property, plant and equipment	(91.0)	(94.2)	(191.2)	(263.8)
Net proceeds from disposal of assets held for sale	-	215.2	-	477.1
Other assets	(0.3)	4.9	11.8	4.0
Contributions in aid of construction	5.8	4.5	8.6	7.5
Cash flow from continuing investing activities	(85.5)	130.4	(170.8)	224.8
Cash flow from discontinued operations	-	(14.2)	-	(21.1)
	(85.5)	116.2	(170.8)	203.7
FINANCING ACTIVITIES				
Repayment of short-term debt	(982.6)	(135.9)	(1,142.5)	(1,403.5)
Proceeds of short-term debt	741.7	109.7	1,142.5	1,237.6
Proceeds of long-term debt (Note 2)	232.1	140.6	232.1	140.6
Repayment of long-term debt and interest rate swaps (Note 3)	(20.9)	(19.8)	(264.3)	(28.5)
Dividend paid	(15.0)	(16.9)	(30.0)	(33.8)
Other long-term liabilities	0.5	(1.2)	(0.9)	(1.5)
	(44.2)	76.5	(63.1)	(89.1)
Increase (decrease) in cash and cash equivalents	35.8	94.4	(4.2)	93.3
Cash and cash equivalents, beginning of period	40.6	44.4	80.6	45.5
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 76.4	$ 138.8	$ 76.4	$ 138.8
Supplementary information:				
Interest paid	$ 26.9	$ 35.4	$ 33.1	$ 42.7
Income taxes paid	3.5	1.7	5.1	5.5
Cash and cash equivalents consist of:				
Cash	$ 75.7	$ 72.3	$ 75.7	$ 72.3
Short-term investments	0.7	66.5	0.7	66.5

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

1. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) have been prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). The accounting policies and presentation applied are consistent with those outlined in the Corporation's audited annual consolidated financial statements for the year ended December 31, 2013.

These interim consolidated financial statements do not include all disclosures required in the annual consolidated financial statements and should be read in conjunction with the annual consolidated financial statements included in ENMAX's 2013 Financial Report. Amounts are stated in millions of Canadian dollars, except as otherwise noted.

ENMAX is subject to fluctuations in the demand for and price of electricity and natural gas; therefore, interim results are not necessarily indicative of annual or future results.

2. FINANCIAL INSTRUMENTS, HEDGES AND RISK MANAGEMENT

RISK ANALYSIS AND CONTROL

ENMAX manages its exposure to market risk (interest rate risk, foreign currency exchange risk, commodity price risk and equity price risk) on a portfolio basis, which includes positions arising from its interests in generation facilities, liability positions arising from its commitments to its customers and transacting positions arising from its hedging activities.

SENSITIVITY ANALYSIS ON MARKET RISKS

The analysis below represents the effect of market risks on the Corporation's results as those risks apply to derivative financial instruments. Non-derivative financial instruments are recorded at cost. The carrying amounts of non-derivative financial instruments are not affected by changes in market variables whereas carrying amounts of derivative financial instruments are affected by market variables.

The following table reflects the sensitivity of the fair value of outstanding derivative instruments to reasonably possible changes in the markets of derivative financial instruments. Market interest rates impact interest rate swaps for comparative periods. Interest rate swaps were settled on March 17, 2014. Foreign currency exchange rates impact commodity derivatives and foreign currency hedge contracts. Forward prices of natural gas and electricity impact commodity derivatives. The market value of equity investments impacts those instruments carried at fair value.

Certain assumptions have been made in arriving at the sensitivity analysis:

- The same fair value methodologies have been used as were used to obtain actual fair values in the fair values section of this note.
- Changes in the fair value of derivative instruments that are effective cash flow hedges are recorded in other comprehensive income (OCI).
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.

- Foreign currency balances, principal and notional amounts are based on amounts as at June 30, 2014 and June 30, 2013.
- Interest rate sensitivities are based on Canadian Dealer Offered Rate.
- Sensitivities are exclusive of any potential income tax impacts.

SENSITIVITIES OF MARKET RISKS

As at June 30
(millions of dollars)

	2014		2013	
	Earnings	OCI	Earnings	OCI
Interest rates increase 100 basis points (1% pure rate change)	–	–	+ 0.5	+ 12.1
Canadian dollar strengthens compared with the U.S. dollar by 10%	**-12.4**	**+0.6**	- 13.3	+ 0.9
Forward price of natural gas increases by 10%	**+0.7**	**+17.7**	- 0.2	+ 5.9
Forward price of electricity increases by 10%	–	**+1.7**	-	+ 26.3

(1) These sensitivities are based on financial instruments carried at fair value, which include derivative contracts. The impact of a change in one factor may be compounded or offset by changes in other factors. This table does not consider the impact of any interrelationship among the factors or taxes. These sensitivities are not necessarily indicative of actual future results.

FOREIGN EXCHANGE AND INTEREST RATE RISK

Foreign exchange and interest rate risks are created by fluctuations in the fair values or cash flows of financial instruments due to changes in foreign exchange rates and/or changes in the market interest rates.

ENMAX is not exposed to significant interest rate risk and volatility as a result of the issuance of fixed-rate long-term debt and the use of interest rate hedging instruments. The fair value of ENMAX's long-term debt and any associated interest rate hedging instruments change as interest rates change, assuming all other variables remain constant. For example, a one per cent increase (decrease) in interest rates as at June 30, 2014, would have an effect on fair value of fixed interest rate debt of $113.8 million increase (decrease) (December 31, 2013—$92.4 million).

Changes in the value of the Canadian dollar relative to the U.S. dollar could impact the Canadian dollar cost of natural gas, which affects the input cost of the Corporation's natural-gas-fired generation capacity, as well as the cost to the Corporation of offering fixed price gas contracts to its customers. The foreign exchange impact on these gas purchases is offset, when possible, by foreign exchange contracts. Foreign exchange exposure resulting from procurement contracts has also been mitigated by foreign exchange contracts.

CREDIT RISK

ENMAX is exposed to credit risk primarily through its wholesale and retail energy sales business. Credit risk is the loss that may result from counterparties' non-performance. ENMAX evaluates the credit risk of wholesale and retail competitive supply activities separately as discussed below.

The Corporation's maximum financial statement exposure to credit risk is the carrying value of the financial assets, as set out in the table below. This maximum exposure does not necessarily reflect losses expected by management nor does it necessarily reflect losses experienced in the past.

FINANCIAL ASSETS

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
Cash and cash equivalents (Note a)	**76.4**	80.6
Accounts receivable (Note b)	**560.0**	665.5
Other current assets (Note c)	**70.1**	42.6
Other long-term assets (Note c)	**36.6**	57.0

(a) Cash and Cash Equivalents

Credit risk associated with cash and cash equivalents is minimized substantially by ensuring these financial assets are placed with governments, well-capitalized financial institutions and other credit-worthy counterparties. Continuous reviews are performed to evaluate changes in the credit worthiness of counterparties.

(b) Accounts Receivable

The majority of the Corporation's accounts receivable are exposed to credit risk. Exposure to credit risk occurs through competitive electricity and natural gas supply activities related to serving residential, commercial and industrial customers. The risk represents the loss that may be incurred due to the non-payment of a customer's accounts receivable balance, as well as the loss that may be incurred from the resale of energy previously allocated to serve the customer. Charges to earnings as a result of credit losses for the Corporation during the three- and six-month periods ended June 30, 2014, totalled $1.9 million and $5.1 million, respectively (2013—$2.2 and $4.2 million). Management monitors credit risk exposure and has implemented measures to mitigate potential losses. In specific situations, this includes, but is not limited to, a reduction of credit limits, requests for additional collateral or restrictions on new transaction terms.

AGING ANALYSIS OF TRADE RECEIVABLES PAST DUE BUT NOT IMPAIRED

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
1–30 days past due	**15.4**	36.1
31–60 days past due	**6.8**	3.4
61 days or more past due	**31.0**	10.0
Total past due	**53.2**	49.5

CHANGES IN THE ALLOWANCE FOR DOUBTFUL ACCOUNTS

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
Provision at the beginning of the period	**7.8**	6.7
Increase to allowance	**5.1**	6.8
Recoveries and write-offs	**(3.8)**	(5.7)
Provision at end of the period	**9.1**	7.8

The remainder of the accounts receivable balance outstanding at June 30, 2014, consists of unbilled revenue accruals. No provision has been recorded due to the minimal credit risk at the consolidated balance sheet date.

(c) Other Current and Long-Term Assets

ENMAX measures wholesale credit risk as the replacement cost for open energy commodity and derivative transactions (both mark-to-market and accrual), adjusted for amounts owed to or due from counterparties for settled transactions and all other amounts owing but not yet due. The replacement cost of open positions represents unrealized gains, net of any unrealized losses, where the Corporation has a legally enforceable right to offset and intends to settle on a net basis. ENMAX monitors and manages the credit risk of wholesale operations through credit policies and procedures that include an established credit approval process, daily monitoring of counterparty credit limits and the use of credit mitigation measures such as margin, collateral, letters of credit and/or prepayment arrangements.

Due to the possibility of extreme volatility in the prices of energy commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If such a counterparty were to fail to perform its obligations under its contract (for example, fail to provide adequate assurances or credit support), ENMAX could incur a loss that could have a material impact on its financial results.

Additionally, if a counterparty were to default and the Corporation were to liquidate all contracts with that entity, the credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions and unbilled deliveries and additional payments, if any, that would have to be made to settle unrealized losses on accrual contracts.

The majority of counterparties enabled for wholesale transactions are rated investment grade (BBB- or higher) by recognized rating agencies.

LIQUIDITY RISK

Liquidity risk is that ENMAX will not be able to meet its financial obligations as they fall due. The Corporation's approach to managing liquidity risk is to ensure it always has sufficient cash and credit facilities to meet its obligations when due.

The following table details the remaining contractual maturities for ENMAX's current and long-term non-derivative financial liabilities, including both the principal and interest cash flows:

CONTRACTUAL MATURITIES OF NON-DERIVATIVE FINANCIAL LIABILITIES

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
2014	**476.0**	581.2
2015	**124.6**	123.0
2016	**136.2**	136.4
2017	**113.5**	115.2
2018	**402.4**	405.8
Thereafter	**1,176.5**	1,124.2

As at June 30, 2014, the Corporation is non-compliant with a financial covenant for Kettles Hill related to non-recourse financing classified as long-term debt on the Consolidated Balance Sheet. The carrying amount of the debt as at June 30, 2014, is $19.9 million.

The following table details the remaining contractual maturities for ENMAX's derivative financial liabilities:

CONTRACTUAL MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES

As at (millions of dollars)	June 30, 2014	December 31, 2013
2014	19.7	29.0
2015	21.5	21.5
2016	2.7	9.6
2017	2.2	6.4
2018	1.8	4.4
Thereafter	3.3	6.0

DERIVATIVE ASSETS AND LIABILITIES

Financial derivative instruments are recorded on the consolidated balance sheet at fair value. As at June 30, 2014, the mark-to-market adjustment based on the fair value of these hedge contracts resulted in unrealized gains or losses on derivative instruments, which are included in the consolidated balance sheets as per the table below:

As at (millions of dollars)	June 30, 2014		December 31, 2013	
	Hedge Instruments	Non-Hedge Derivatives	Hedge Instruments	Non-Hedge Derivatives
Assets				
Current	39.2	3.4	19.7	9.9
Non-current	16.2	1.5	18.3	8.1
Liabilities				
Current	23.9	8.8	19.6	9.4
Non-current	14.5	4.0	22.8	25.1

Cash flow hedges are used to manage the variability of cash flows resulting from the purchase and sale of electricity and natural gas, as well as foreign exchange exposure. For cash flow hedges, changes in the fair value of the effective portion of the hedging derivative are accumulated in OCI and recognized in net earnings during the periods when the variability in cash flows of the hedged item is realized. In the first half of 2014, there was no impact (2013—nil) recognized in earnings as a reflection of the ineffectiveness of the relevant hedges. Gains and losses on cash flow hedges are reclassified immediately to net earnings when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer likely to occur. During the three and six months ended June 30, 2014, there was nil and $11.2 million impact to earnings, respectively (2013—nil), related to the interest rate swap hedge that was terminated, on March 17, 2014, upon repayment of the non-recourse term financing.

Foreign exchange exposures on the Corporation's futures margin trading account are managed through economic hedges. For these hedges, the change in the fair value of the hedging derivative and the hedged items are recognized directly in net earnings. During the three and six months ended June 30, 2014, there was no impact (2013—nil) recognized.

The Corporation estimates that, of the $10.8 million of gains reported in accumulated OCI as at June 30, 2014, gains of $15.3 million are expected to be realized within the next 12 months, which will be offset by long-term losses at market prices in effect at the time of settlement.

Non-hedge derivatives are classified as held for trading and recognized at fair market value with changes in fair market value being recorded through earnings. In the three and six months ended June 30, 2014, there were losses of $1.3 million and gains $8.6 million (2013—$4.3 million gain and $5.4 million gain) recorded in net earnings.

FAIR VALUE

Level Determination and Classifications

The Level I, II and III classifications in the fair value hierarchy used by the Corporation are defined as follows:

Level I

Fair values are determined using inputs that are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Corporation has the ability to access. In determining Level I, the Corporation uses quoted prices for identically traded commodities obtained from active exchanges such as the New York Mercantile Exchange and the Natural Gas Exchange.

Level II

Fair values are determined using inputs other than quoted prices that are observable for the asset or liability, either directly or indirectly.

Fair values are determined using inputs including interest rate yield curves, forward market rates, quoted commodity prices or credit spreads that are readily observable and reliable or for which unobservable inputs are deemed to be insignificant to the fair values that are categorized as Level II.

Commodity contracts' fair values falling within the Level II category are determined through the use of quoted prices in active markets adjusted for factors specific to the asset or liability. Level II fair values include those determined using pricing applications for creating power curves where the inputs are readily observable, including commodity prices for similar assets or liabilities in active markets.

Interest rate swap contract fair values falling within the Level II fair values include those determined by using a benchmark index and applying that index to the notional debt outstanding.

Level III

The fair values are determined using significant unobservable data or inputs.

In rare circumstances, ENMAX enters into commodity transactions with non-standard features for which market-observable data are not available. In these cases, Level III fair values are determined using valuation techniques with inputs that are based on historical data.

FAIR VALUES OF THE CORPORATION'S FINANCIAL ASSETS AND LIABILITIES

As at June 30, 2014 *(millions of dollars)*	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs [1] (LEVEL II)	Significant Unobservable Inputs [2] (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	0.2	46.6	8.9	55.7
Foreign currency forward contracts	–	4.6	–	4.6
Financial assets total	0.2	51.2	8.9	60.3
Financial liabilities measured at fair value:				
Energy trading forward contracts	(0.2)	(48.0)	–	(48.2)
Foreign currency forward contracts	–	(3.0)	–	(3.0)
Financial liabilities total	(0.2)	(51.0)	–	(51.2)
Net risk management assets (liabilities)	–	0.2	8.9	9.1

(1) Excludes financial assets and liabilities where carrying value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities).

(2) Market-observable data are not available. Fair values are determined using valuation techniques.

FAIR VALUES OF THE CORPORATION'S FINANCIAL ASSETS AND LIABILITIES

As at December 31, 2013 *(millions of dollars)*	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs [1] (LEVEL II)	Significant Unobservable Inputs [2] (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	–	27.1	11.1	38.2
Foreign currency forward contracts	–	6.9	–	6.9
Interest rate swap	–	10.9	–	10.9
Financial assets total	–	44.9	11.1	56.0
Financial liabilities measured at fair value:				
Energy trading forward contracts	–	(41.4)	–	(41.4)
Interest rate swap	–	(35.5)	–	(35.5)
Financial liabilities total	–	(76.9)	–	(76.9)
Net risk management assets (liabilities)	–	(32.0)	11.1	(20.9)

(1) Excludes financial assets and liabilities where carrying value approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities).

(2) Market-observable data are not available. Fair values are determined using valuation techniques.

The following table summarizes the key factors impacting the change in the fair value of the Corporation's Level III net risk management assets and liabilities separately by source of valuation during the period ended June 30, 2014:

CHANGE IN FAIR VALUE OF LEVEL III RISK MANAGEMENT ASSETS AND LIABILITIES

(millions of dollars)	Hedges
Net risk management assets as at December 31, 2013	11.1
Changes attributable to:	
Commodity price changes	(0.7)
Transfers in/out of Level III	(1.5)
Net risk management assets as at June 30, 2014	8.9
Total change in fair value included in OCI	(2.2)
Total change in fair value included in pre-tax earnings	–

NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES

Cash, cash equivalents and restricted cash are recorded at fair market value. Fair values for accounts receivable, short-term debt, accounts payable and accrued liabilities are not materially different from their carrying amounts due to their short-term nature.

The fair value of the Corporation's long-term debt was estimated based on quoted market prices for the same or similar debt instruments. When such information was not available, future payments of interest and principal were discounted at estimated interest rates that were made available to ENMAX for comparable credit-rated entities to the Corporation.

CARRYING AMOUNTS AND FAIR VALUES OF LONG-TERM DEBT

As at *(millions of dollars)*	June 30, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt [1], consisting of:				
Debentures, with remaining terms of				
Less than 5 years	74.3	77.5	34.0	35.4
6–10 years	91.3	99.2	122.4	132.4
11–15 years	22.3	25.5	14.4	16.1
16–20 years	274.4	311.7	187.1	205.6
21–25 years	657.5	672.5	557.6	571.6
Private debentures				
Series 1 (6.15%)	298.3	339.9	298.2	338.8
Non-recourse Kettles term financing (2013 amount includes CEC [2])	19.9	21.8	220.5	207.2
Promissory note	4.6	4.9	4.8	4.9
	1,442.6	1,553.0	1,439.0	1,512.0

(1) Includes current portion of $61.5 million (December 31, 2013—$63.7 million). Maturity dates range from May 2015 to June 2039.

(2) On March 17, 2014, $200.6 million of non-recourse term financing related to CEC was repaid.

On June 15, 2014, the Corporation obtained $232.1 million of 5-, 10-, 20- and 25-year debentures from The City of Calgary (The City) through arrangements with the Alberta Capital Finance Authority (ACFA) (2013 - $140.6 million 5-, 10-, 20- and 25-year debentures) to fund ongoing investment relating to regulated transmission and distribution network in Calgary and the surrounding area. This brings total amount of debt owed to The City to $1,119.8 million at June 30, 2014 (December 31, 2013—$915.5 million).

3. NON-RECOURSE TERM FINANCING REPAYMENT

On March 17, 2014, $200.6 million of non-recourse term financing and $35.6 million of a fixed-for-floating interest rate swap related to CEC was repaid prior to maturity on September 2026. In addition, ENMAX settled back-to-back swaps that were initially executed as a hedging relationship in relation to the fixed-for-floating swap. The settlement of the back-to-back swaps was $0.4 million. Settlement costs of $20.7 million associated with the termination of the interest rate swaps were recorded as interest expense.

4. FINANCIAL STATEMENT EFFECTS OF RATE REGULATION

Under regulatory accounting, the timing of recognition of certain assets, liabilities, revenues and expenses may differ from what is otherwise expected under GAAP for non-regulated operations. ENMAX has recorded the following regulatory assets and liabilities:

REGULATORY ASSETS AND LIABILITIES

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
Regulatory assets		
Accounts receivable: purchased power variances (Note a)	-	41.5
Distribution and Transmission assets: Inter-company profit on construction of regulated PPE (Note b)	39.7	38.4
Other regulatory assets (Note c)	52.4	42.2
Total regulatory assets	92.1	122.1
Regulatory liabilities		
Accounts payable purchased power variances (Note a)	2.7	-
Other regulatory liabilities (Note d)	7.3	1.9
Total regulatory liabilities	10.0	1.9

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event. Regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods, which are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be returned to customers as a result of the rate-setting process.

(a) Purchased Power Variances

Purchased power costs are included in allowed rates on a forecast basis. For rate-setting purposes, differences between forecast and actual purchased power costs in the rate year are held until the following year. ENMAX Power recognizes purchased power cost variances as a regulatory asset or liability based on the expectation that amounts held from one year to the next for rate-setting purposes will be approved for collection from, or refund to, future customers. The regulatory asset represents the excess of actual over forecast purchased power costs. In the absence of rate regulation, GAAP would require that actual purchased power costs be recognized as an expense when incurred. In this case, operating results for the three and six months ended June 30, 2014, would have been $12.3 million higher (2013—$28.7 million lower) and $44.2 million higher (2013—$28.0 million lower), respectively. As at June 30, 2014, the balance is a refund to future customers and is reported as a regulatory payable.

(b) Inter-company Profit on Construction of Regulated Property, Plant and Equipment

Distribution assets for the regulated operations of ENMAX Power include intercompany profit relating to construction work performed by an ENMAX subsidiary. Such profit is deemed for regulatory purposes to be realized to the extent that the transfer price is recognized for rate-making purposes by the regulator and included in the capital cost. In the absence of rate regulation, GAAP would require that intercompany profits be eliminated upon consolidation. If these intercompany profits had been eliminated, the impact on current period earnings for the three and six months ended June 30, 2014, would be a reduction of $1.2 million (2013—$0.2 million reduction) and reduction of $1.3 million (2013 - $0.9 million reduction) respectively, representing the profit or loss on these services. The balances for property, plant and equipment (PPE) and retained earnings at June 30, 2014, would be further reduced by $39.7 million (December 31, 2013—$38.4 million reduction).

(c) Other Regulatory Assets

Other regulatory assets primarily relate to the Alberta Utilities Commission (AUC) flow-through items and other costs that will be collected from customers through future rates.

(d) Other Regulatory Liabilities

Other regulatory liabilities primarily relate to items that will be refunded to customers through future rates.

For certain regulatory items identified above, the expected recovery or settlement period, or likelihood of recovery or settlement, is affected by risks and uncertainties relating to the ultimate authority of the regulator in determining the item's treatment for rate-setting purposes. For example, ENMAX's treatment of purchased power costs is dependent on the continued use of an automatic adjustment mechanism for regulatory purposes and would require reconsideration if the regulator decided to discontinue the use of this mechanism or to require ENMAX Power to absorb cost variances in a particular year. Similarly, there is a risk the regulator may disallow a portion of certain costs incurred in the current period for recovery through future rates or disagree with the proposed recovery period.

OTHER ITEMS AFFECTED BY RATE REGULATION

Current regulations exclude the Corporation's transmission, distribution and regulated rate electricity sales earnings from corporate income taxes, although regulated rate electricity sales are subject to Payment in Lieu of Tax (PILOT). Accordingly, ENMAX Power has not recognized current or future corporate income taxes on tax-exempt earnings. In the event regulations change, it would be expected that when these amounts became payable, they would be recovered through future rate revenues.

Gains and losses on the disposal and retirement of regulated depreciable assets are deferred and amortized over the estimated remaining service life of similar assets, through a charge to accumulated amortization equal to the net book value of the disposed or retired asset. In the absence of rate regulation, under GAAP the difference between the proceeds and net book value would be charged or credited to earnings in the period the asset is disposed of or retired. The amount deferred from current period earnings for the three and six months ended June 30, 2014, was a $0.2 million loss (2013—$1.1 million loss) and $0.2 million loss (2013—$6.8 million loss), respectively representing the gains and losses on disposals and retirements of regulated assets.

5. OTHER ASSETS AND LIABILITIES

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
Other current assets		
Hedge instruments	**39.2**	19.7
Non-hedge derivatives	**3.4**	9.9
Prepaid expenses	**26.8**	12.3
Inventory	**0.7**	0.7
	70.1	42.6
Other long-term assets		
Hedge instruments	**16.2**	18.3
Non-hedge derivatives	**1.5**	8.1
Restricted cash	**–**	8.4
Shares in other companies	**0.2**	0.1
Prepaid expenses	**3.6**	3.6
Long-term accounts receivable	**5.9**	9.2
Other	**9.2**	9.3
	36.6	57.0
Other current liabilities		
Hedge instruments	**23.9**	19.6
Non-hedge derivative	**8.8**	9.4
Deposits	**19.8**	18.6
Deferred revenue	**3.0**	5.2
	55.5	52.8
Other long-term liabilities		
Hedge instruments	**14.5**	22.8
Non-hedge derivative	**4.0**	25.1
Long-term payables	**6.6**	8.0
Deferred revenue	**5.3**	4.8
	30.4	60.7

6. PROPERTY, PLANT AND EQUIPMENT

As at June 30, 2014 (millions of dollars)	Cost	Accumulated Amortization	Net Book Value
Transmission, distribution and substation equipment	2,055.6	(598.2)	1,457.4
Generation facilities and equipment	1,041.2	(236.6)	804.6
Construction in progress	967.5	–	967.5
Buildings and site development	237.5	(70.3)	167.2
Tools, systems and equipment	97.0	(67.0)	30.0
Land	37.3	–	37.3
Capital spares and other	37.8	–	37.8
Vehicles	32.6	(12.9)	19.7
	4,506.5	(985.0)	3,521.5
Government grants	(20.0)	2.7	(17.3)
Contributions in aid of construction	(475.3)	103.5	(371.8)
	4,011.2	(878.8)	3,132.4

As at December 31, 2013 (millions of dollars)	Cost	Accumulated Amortization	Net Book Value
Transmission, distribution and substation equipment	2,024.7	(577.6)	1,447.1
Generation facilities and equipment	1,040.1	(218.6)	821.5
Construction in progress	922.5	–	922.5
Buildings and site development	208.9	(65.9)	143.0
Tools, systems and equipment	93.9	(65.4)	28.5
Land	34.5	–	34.5
Capital spares and other	33.6	–	33.6
Vehicles	32.8	(12.7)	20.1
	4,391.0	(940.2)	3,450.8
Government grants	(20.0)	2.3	(17.7)
Contributions in aid of construction	(509.4)	98.9	(410.5)
	3,861.6	(839.0)	3,022.6

7. EMPLOYEE FUTURE BENEFITS

The Corporation has a registered pension plan that substantially covers all employees and includes both defined benefit (DB) and defined contribution (DC) provisions. The DB provisions provide a pension based on years of service and highest average earnings over five consecutive years of employment. DB pension benefits under the registered plan will increase annually by at least 60 per cent of the consumer price index for Alberta. Under the DC provisions, employer contributions are based on the participating members' pensionable earnings and contribution levels.

The Corporation also sponsors a supplemental pension plan providing an additional DB pension based on years of service and highest average earnings (including incentive pay) to both DB and DC members whose benefits are limited by maximum pension rules under the Income Tax Act. The supplemental pension plan benefits do not automatically increase. In addition, the Corporation provides employees with post-retirement benefits other than pensions, including extended health and dental benefits beyond those provided by government-sponsored plans, life insurance and a lump-sum allowance payable at retirement, up to age 65.

The total employee benefit cost recorded in the consolidated statement of earnings and comprehensive income for the three and six months ended June 30, 2014, is $5.6 million (2013—$5.9 million) and $11.8 million (2013—$11.9 million), respectively.

8. SHORT-TERM DEBT

The Corporation has unsecured credit facilities amounting to $1,150.0 million (December 31, 2013—$1,150.0 million) to fund general operating requirements and to provide liquidity support for commercial paper and commodity marketing programs. Combined, all of the facilities encompass $900.0 million in bilateral credit facilities and $250.0 million of syndicated credit facilities. As at June 30, 2014, $251.8 million (2013—$443.2 million) of operating facilities and $30.0 million (2013—$30.0 million) of syndicated facilities were used in support of outstanding letters of credit.

At June 30, 2014, the Corporation had no short-term debt (December 31, 2013—nil).

9. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

As at *(millions of dollars)*	June 30, 2014	December 31, 2013
Unrealized losses on available-for-sale financial assets	-	(0.1)
Unrealized gains (losses) on derivatives designated as cash flow hedges	10.8	(6.2)
Accumulated other comprehensive income (losses), including a future income tax expense of $6.3 million (2013—expense of $1.7 million)	10.8	(6.3)

10. COMMITMENTS AND CONTINGENCIES

PROPERTY, PLANT AND EQUIPMENT

As at June 30, 2014, the Corporation is committed to major capital expenditures over the next five years and thereafter, with minimum annual payments totalling $70.6 million.

OBLIGATIONS UNDER OTHER AGREEMENTS

The Corporation rents premises, vehicles and equipment under multiple lease contracts with varying expiration dates.

The Corporation is obligated to make monthly payments in return for the output from power purchase arrangements (PPAs) and other tolling arrangements, based on normal operating conditions adjusted for inflation, other than in the event of a forced outage.

The Corporation commits to the purchase of renewable energy certificates and carbon offset credits. The Corporation commits to long-term service arrangements on certain generating assets.

The aggregated minimum payments under these arrangements total $98.1 million.

ENVIRONMENTAL

Provincial regulations aimed at reducing the levels of greenhouse gas (GHG) emissions took effect July 2007. Due to the change of law provisions in ENMAX Energy's PPAs and tolling agreements, ENMAX Energy is exposed to the associated compliance costs.

For the three- and six-month periods ended June 30, 2014, the cost of electricity services provided includes a charge to earnings in the amount of $4.3 million (2013—$3.9 million) and $8.6 million (2013—$8.4 million), relating to estimated compliance costs under the provincial GHG regulations for ENMAX Energy's interests in coal and natural-gas-fired generation facilities through its PPAs and owned assets. Compliance payments are due to the Province of Alberta directly, or via plant owners, by June 30 of the year following the compliance year. ENMAX Energy has taken steps, including acquiring qualified offset credits both from its wind-generation assets and purchases on the wholesale market, to mitigate impacts of the GHG regulations.

LETTERS OF CREDIT

In the normal course of operations, letters of credit are issued to facilitate the extension of sufficient credit for counterparties having credit exposure to the Corporation or its subsidiaries. As at June 30, 2014, the Corporation had issued letters of credit amounting to $281.8 million (December 31, 2013—$303.9 million).

11. SEGMENTED INFORMATION

	ENMAX Energy		ENMAX Power		Corporate & Intersegment Eliminations		Consolidated Totals	
THREE MONTHS ENDED JUNE 30 *(millions of dollars)*	2014	2013	2014	2013	2014	2013	2014	2013
REVENUE (Note 16)								
Electricity	560.1	722.6	32.8	36.3	(90.7)	(83.8)	502.2	675.1
Natural gas	100.6	71.8	-	-	(0.1)	(0.1)	100.5	71.7
Transmission and distribution	-	-	100.4	74.7	-	-	100.4	74.7
Local access fees	-	-	30.9	28.3	-	-	30.9	28.3
Contractual services	1.2	0.7	25.2	16.0	3.3	1.9	29.7	18.6
Other	4.9	4.3	0.6	1.2	(1.8)	(1.3)	3.7	4.2
TOTAL REVENUE	666.8	799.4	189.9	156.5	(89.3)	(83.3)	767.4	872.6
COST OF SERVICES PROVIDED								
Electricity	461.3	667.1	27.1	30.1	(90.2)	(83.4)	398.2	613.8
Natural gas	93.8	67.0	-	-	-	-	93.8	67.0
Transmission and distribution	-	-	25.4	20.9	-	-	25.4	20.9
Local access fees	-	-	30.9	28.3	-	-	30.9	28.3
Contractual services	0.7	0.2	17.5	13.5	-	-	18.2	13.7
Operations, maintenance and administration (OM&A) (Note 16)	43.4	48.9	40.1	37.0	(0.9)	(1.8)	82.6	84.1
Foreign exchange loss (gain)	5.2	(4.9)	(0.1)	-	-	-	5.1	(4.9)
TOTAL COSTS OF SERVICES PROVIDED	604.4	778.3	140.9	129.8	(91.1)	(85.2)	654.2	822.9
EARNINGS BEFORE AMORTIZATION INTEREST AND INCOME TAXES	62.4	21.1	49.0	26.7	1.8	1.9	113.2	49.7
Amortization	26.3	26.8	16.0	15.3	0.7	0.9	43.0	43.0
EARNINGS BEFORE INTEREST AND INCOME TAXES	36.1	(5.7)	33.0	11.4	1.1	1.0	70.2	6.7
Interest							5.3	6.3
Income tax expense (recovery)							1.3	(7.8)
NET EARNINGS FROM CONTINUING OPERATIONS							63.6	8.2
Net earnings from discontinued operations							-	1.1
Gain on sale of subsidiary								175.9
NET EARNINGS							63.6	185.2
GOODWILL	16.0	16.0	–	–	–	–	16.0	16.0
CAPITAL ADDITIONS	38.6	67.3	50.5	43.5	6.0	7.5	95.1	118.3

SIX MONTHS ENDED JUNE 30 (millions of dollars)	ENMAX Energy 2014	ENMAX Energy 2013	ENMAX Power 2014	ENMAX Power 2013	Corporate & Intersegment Eliminations 2014	Corporate & Intersegment Eliminations 2013	Consolidated Totals 2014	Consolidated Totals 2013
REVENUE (Note 16)								
Electricity	**1,237.6**	1,342.1	**70.2**	78.6	**(188.0)**	(178.1)	**1,119.8**	1,242.6
Natural gas	**332.0**	209.3	–	–	**(0.6)**	(0.4)	**331.4**	208.9
Transmission and distribution	–	–	**192.4**	151.5	–	–	**192.4**	151.5
Local access fees	–	–	**66.6**	59.5	–	–	**66.6**	59.5
Contractual services	**1.7**	1.5	**43.1**	35.4	**6.4**	2.0	**51.2**	38.9
Other	**9.9**	15.1	**1.8**	2.5	**(3.2)**	(3.0)	**8.5**	14.6
TOTAL REVENUE	**1,581.2**	1,568.0	**374.1**	327.5	**(185.4)**	(179.5)	**1,769.9**	1,716.0
COST OF SERVICES PROVIDED								
Electricity	**1,058.2**	1,193.4	**58.7**	66.5	**(187.3)**	(177.4)	**929.6**	1,082.5
Natural gas	**311.4**	190.6	**-**	–	–	–	**311.4**	190.6
Transmission and distribution	–	–	**52.5**	45.8	–	–	**52.5**	45.8
Local access fees	–	–	**66.6**	59.5	–	–	**66.6**	59.5
Contractual services	**0.8**	0.7	**30.9**	27.6	–	(0.2)	**31.7**	28.1
Operations, maintenance and administration (OM&A) (Note 16)	**84.5**	93.5	**82.6**	72.9	**(2.6)**	(5.3)	**164.5**	161.1
Foreign exchange loss (gain)	**0.1**	(6.5)	**-**	–	**0.1**	–	**0.2**	(6.5)
TOTAL COSTS OF SERVICES PROVIDED	**1,455.0**	1,471.7	**291.3**	272.3	**(189.8)**	(182.9)	**1,556.5**	1,561.1
EARNINGS BEFORE AMORTIZATION INTEREST AND INCOME TAXES	**126.2**	96.3	**82.8**	55.2	**4.4**	3.4	**213.4**	154.9
Amortization	**53.3**	53.3	**29.5**	28.1	**2.0**	1.8	**84.8**	83.2
EARNINGS BEFORE INTEREST AND INCOME TAXES	**72.9**	43.0	**53.3**	27.1	**2.4**	1.6	**128.6**	71.7
Interest							**33.0**	13.1
Income tax recovery							**(3.9)**	(4.7)
NET EARNINGS FROM CONTINUING OPERATIONS							**99.5**	63.3
Net earnings from discontinued operations							**-**	4.3
Gain on sale of subsidiary							**-**	175.9
NET EARNINGS							**99.5**	243.5
GOODWILL	**16.0**	16.0	**–**	–	**–**	–	**16.0**	16.0
CAPITAL ADDITIONS	**74.0**	145.1	**87.9**	73.4	**9.7**	11.6	**171.6**	230.1

SEGMENTED TOTAL ASSETS

As at (millions of dollars)	June 30, 2014	December 31, 2013
ENMAX Energy	**2,818.8**	2,881.8
ENMAX Power	**1,561.9**	1,540.0
Corporate and eliminations	**156.1**	143.7
	4,536.8	4,565.5

12. ITEMS NOT INVOLVING CASH

(millions of dollars)	THREE MONTHS ENDED JUNE 30, 2014	THREE MONTHS ENDED JUNE 30, 2013	SIX MONTHS ENDED JUNE 30, 2014	SIX MONTHS ENDED JUNE 30, 2013
Amortization	43.0	43.0	84.8	83.2
Future income taxes	0.7	(19.7)	(5.4)	(17.3)
Change in unrealized market value of financial contracts	1.3	(4.3)	27.4	(5.5)
Other	0.6	1.2	0.9	1.2
	45.6	20.2	107.7	61.6

13. CHANGE IN NON-CASH WORKING CAPITAL

(millions of dollars)	THREE MONTHS ENDED JUNE 30, 2014	THREE MONTHS ENDED JUNE 30, 2013	SIX MONTHS ENDED JUNE 30, 2014	SIX MONTHS ENDED JUNE 30, 2013
Accounts receivable	144.7	(81.5)	105.4	(43.5)
Income tax receivable	(3.3)	13.7	(4.2)	7.4
Other current assets	(14.5)	1.8	(14.4)	2.8
Accounts payable and accrued liabilities	(65.3)	(54.7)	(62.5)	(98.1)
Other current liabilities	(4.3)	(10.6)	(1.1)	(9.5)
	57.3	(131.3)	23.2	(140.9)

14. JOINT VENTURE INVESTMENTS

In 2002, the Corporation entered into a joint venture agreement (JVA) with Vision Quest Windelectric Inc. to build and operate 114 wind turbines in southern Alberta (McBride). The turbines began generating electricity in 2003, and the Corporation has a 50 per cent ownership interest. The Corporation has also agreed to purchase 100 per cent of the output from the wind farm under a 20-year PPA.

In 2010, the Corporation entered into a JVA with SNC-Lavalin Constructions Inc. (SNC-Lavalin) to design and construct certain portions of the West LRT in Calgary. Construction was completed and the West LRT was operational as of December 10, 2012.

In 2012, Capital Power LP (CPLP) agreed to purchase a 50 per cent interest in Shepard Energy Center (Shepard) and enter into a JVA to construct and operate the facility. The sale of the 50 per cent interest in Shepard was completed September 30, 2013.

PROPORTIONATE SHARE OF THE JOINT VENTURES' NET ASSETS

For the period ended (millions of dollars)	June 30, 2014				December 31, 2013			
	Shepard	McBride	SNC-Lavalin	Total	Shepard	McBride	SNC-Lavalin	Total
Cash and cash equivalents	10.3	–	0.7	11.0	7.4	–	0.6	8.0
Accounts receivable	3.5	–	–	3.5	6.8	0.2	0.1	7.1
Other current assets	5.7	0.3	–	6.0	6.2	–	–	6.2
PPE	812.7	32.2	–	844.9	745.0	33.4	–	778.4
Other long term assets	5.0	–	–	5.0	5.0	–	–	5.0
Accounts payable	(27.7)	(0.7)	–	(28.4)	(25.8)	(0.3)	–	(26.1)
Other current liabilities	(2.8)	–	(0.1)	(2.9)	–	–	–	–
Other long-term liabilities	–	(4.2)	–	(4.2)	–	(4.3)	–	(4.3)
Proportionate share in net assets of joint ventures	806.7	27.6	0.6	834.9	744.6	29.0	0.7	774.3

PROPORTIONATE SHARE OF THE JOINT VENTURES' CASH FLOWS

For the period ended (millions of dollars)	June 30, 2014				December 31, 2013			
	Shepard	McBride	SNC-Lavalin	Total	Shepard	McBride	SNC-Lavalin	Total
Operating activities	–	(0.1)	–	(0.1)	–	4.5	(4.3)	0.2
Investing activities	(61.0)	–	–	(60.9)	273.5	–	–	273.5
Financing activities	63.9	0.1	–	64.0	(266.1)	(4.5)	–	(270.6)
Proportionate share in the increase (decrease) in cash and cash equivalents of joint venture	2.9	–	–	3.0	7.4	–	(4.3)	3.1

McBride generated a net loss of $1.4 million for the six months ended June 30, 2014 (2013—net earnings of $1.4 million).

15. RELATED PARTY TRANSACTIONS

ENMAX's related party transactions are comprised of both revenues from and expenditures to The City. The City is the sole shareholder of the Corporation. Total revenues received from The City for the three and six months ended June 30, 2014, were $24.9 million and $65.5 million, respectively (2013—$24.8 and $62.5 million). The significant components include contract sales of electricity, construction of infrastructure, provision of non-regulated power distribution services and billing and customer care services relating to The City's utilities departments. ENMAX has committed to a water supply agreement with The City, to commence upon completion of Shepard, whereby The City will supply a specified amount of water annually to facilitate Shepard operations.

As at June 30, 2014, amounts owing to the Corporation from The City for services provided were $25.0 million (December 31, 2013—$31.2 million).

Total expenditures for goods and services received from The City for the three and six months ended June 30, 2014, were $31.9 million and $68.9 million, respectively (2013—$29.5 million and $63.5 million, respectively). Most of these expenditures were for local access fees for use of The City's rights-of-way, the cost of which is passed through ENMAX directly to transmission and distribution customers. The measurement basis used in determining the above values is the contract amount that is considered fair market value; that is, the measurement basis that would be used for a third-party arm's-length transaction.

In 2009, the Corporation entered into a capital lease agreement with The City for the use of its land and buildings. As at June 30, 2014, the assets under the capital lease were $4.2 million (December 31, 2013—$4.3 million), and the capital lease obligation was $4.6 million (December 31, 2013—$4.6 million).

In addition, on June 15, 2014, the Corporation obtained $232.1 million from The City through arrangements with the ACFA to fund ongoing investment relating to the regulated transmission and distribution network in Calgary and the surrounding area. This brings the total amount of debt owed to The City to $1,119.8 million at June 30, 2014 (December 31, 2013—$915.5 million). Interest paid for the three and six months ended June 30, 2014, was $16.4 million and $18.9 million, respectively (2013—$15.0 million and $17.8 million, respectively). Principal payments of $27.8 million were made during the six months ended June 30, 2014 (2013—$24.4 million). In addition, ENMAX is required to pay a management fee to The City of 0.25 per cent on the average monthly outstanding debenture balance held by The City on behalf of ENMAX. The administration fee paid for the three and six months ended June 30, 2014, was $0.6 million and $1.2 million, respectively (2013—$0.5 million and $1.0 million).

Transactions between the Corporation and The City have been recorded at the exchange amounts. Exchange amounts are the amounts as outlined by the contracts in effect between the Corporation and The City.

16. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current period's presentation.

At January 1, 2014, there was a reporting presentation change. Billing recoveries related to electricity, natural gas and penalty revenues were previously netted against operations, maintenance and administration (OM&A) expense. Based on the nature of the recoveries and revenues, it was management's decision that it was appropriate to attribute billing recoveries to the margins of electricity, natural gas and contractual services and other, respectively. The reclassification for the three-month period ended June 30, 2013, was an increase in electricity revenue of $9.0 million, natural gas revenue of $2.2 million, other revenue of $1.9 million, electricity costs of $0.1 million and OM&A of $13.1 million. And the reclassification for the six-month period ended June 30, 2013, was an increase in electricity revenue of $17.6 million, natural gas revenue of $4.2 million, other revenue of $4.6 million, electricity costs of $0.2 million and OM&A of $26.1 million. This presentation change does not impact net earnings. The change in presentation has been applied to the comparative periods.

17. SUBSEQUENT EVENTS

On July 11, 2014, ENMAX's unsecured credit facilities were amended. The total unsecured credit facilities remain at $1,150.0 million, with $900.0 million in bilateral credit facilities and $250.0 million of syndicated credit facilities. The Letter of Credit tranches were increased from $300.0 million to $375.0 million capacity and extended by one year to July 20, 2017. Additionally, the $775 million operating tranches were extended by two years to July 20, 2019.

ADDITIONAL INFORMATION

ENMAX welcomes questions from stakeholders.
Additional information relating to ENMAX can be found at enmax.com.

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