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2015 | Q2 INTERIM REPORT

ENMAX Corporation | Three & Six Months Ended June 30, 2015

HIGHLIGHTS

(millions of dollars, except where otherwise noted)	Three Month Ended June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Revenues	713.5	752.1	1,519.9	1,755.8
Adjusted operating margin (1)	175.3	190.0	390.0	387.3
Net earnings	20.3	65.8	90.7	103.6
Earnings before interest, income tax, depreciation and amortization (EBITDA) (1)	86.6	116.8	224.7	220.4
Earnings before interest and income taxes (EBIT) (1)	29.3	73.6	118.6	135.1
Funds from operations (1)	81.4	112.1	189.9	213.1
Cash flow from operations	186.9	181.1	317.9	252.1
Return on equity (2)			7.4%	9.2%
Total assets			5,415.2	4,726.5
Capital additions	67.1	95.1	168.6	171.6
Total recordable injury frequency (TRIF) (3)			1.05	0.51

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

(2) Return on equity (ROE) is equal to net earnings for the 12-month rolling period divided by average shareholder's equity for the 12-month rolling period.

(3) TRIF indicates the rate of injuries at ENMAX, including lost-time incidents, restricted work injuries and medical aids. It is calculated as the number of injuries multiplied by 200,000 (approximate number of hours worked by 100 workers in a year) divided by total number of hours worked.

CAUTION TO READER

This document contains statements about future events and financial and operating results of ENMAX Corporation (ENMAX or the Corporation) and its subsidiaries 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 Financial 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 Financial 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 Financial Report. Intended, planned, anticipated, believed, estimated or expected and other forward-looking statements included in this Financial Report herein should not be unduly relied upon. These statements speak only as of the date of this Financial 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 2015 are described in the Outlook Section of the Management's Discussion and Analysis (MD&A).

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;
- 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 the 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 human-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 the Corporation's reports and other public disclosure documents.

For further information, see the MD&A Risk Management and Uncertainties section.

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

This MD&A, dated August 26, 2015, is a review of the results of operations of ENMAX Corporation (ENMAX or the Corporation) and its subsidiaries for the three and six months ended June 30, 2015, compared with 2014, and of the Corporation's financial condition at June 30, 2015. 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.

The MD&A should be read in conjunction with the accompanying unaudited Condensed Consolidated Interim Financial Statements of the Corporation for the three and six months ended June 30, 2015, and the notes thereto, as well as the audited Consolidated Financial Statements of the Corporation for the year ended December 31, 2014, and related MD&A. The accompanying Condensed Consolidated Interim Financial Statements have been prepared in accordance with the International Financial Reporting Standards (IFRS) for Canadian publicly accountable enterprises as issued by the International Accounting Standards Boards, International Accounting Standard 34 (IAS 34), Interim Financial Reporting and International Financial Reporting Standards 1 (IFRS 1) and First-Time Adoption of IFRS and are stated in Canadian dollars.

On January 1, 2015, the Corporation adopted IFRS for interim and annual Condensed Consolidated Financial Statements, including comparative periods.

The Condensed Consolidated Interim Financial Statements and MD&A were reviewed by ENMAX's Audit, Finance and Risk Committee (AFRC), and the Condensed Consolidated Interim 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-IFRS financial measures such as operating margin, EBITDA, EBIT and funds from operations that are used by management to evaluate performance of business units and segments. Because non-IFRS financial measures do not have a standardized meaning, the Corporation has defined and reconciled them with their nearest IFRS measure. For the reader's reference, the definition, calculation and reconciliation of consolidated non-IFRS financial measures is provided in the Non-IFRS 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)	**2015**	**2014**	**2015**	**2014**
Total revenue	**713.5**	752.1	**1,519.9**	1,755.8
Adjusted operating margin [1]	**175.3**	190.0	**390.0**	387.3
EBITDA [1]	**86.6**	116.8	**224.7**	220.4
EBIT [1]	**29.3**	73.6	**118.6**	135.1
Net earnings	**20.3**	65.8	**90.7**	103.6

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

ENMAX's consolidated net earnings for the three and six months ended June 30, 2015, are $20.3 million and $90.7 million, respectively, compared with $65.8 million and $103.6 million respectively for the three and six months ended June 30, 2014. The net earnings decrease of $45.5 million for the three months ended June 30, 2015, are primarily due to decreased electricity margins, an increase in both amortization and financing charges associated with the impact of ENMAX and Capital Power's new 800 megawatts (MW) combined cycle natural gas plant (Shepard Energy Centre or Shepard) becoming operational and a decrease in transmission and distribution margins due to the 2014 impact of a recovery upon receipt of a regulatory ruling. Partially offsetting these decreases are tax recoveries.

The net earnings decrease of $12.9 million for the six months ended June 30, 2015, is primarily due to increased amortization associated with Shepard becoming operational and a decrease in electricity margins and transmission and distribution margins. The decrease was partially offset by foreign exchange gains and the impact in 2014 of an outage at Keephills Unit 2. An increase in finance charges associated with a decrease in capitalized interest due to the operational impact of Shepard was offset by the impact in the comparative prior period of increased finance charges of $20.7 million associated with an early repayment of long-term debt.

Results of operations are not necessarily indicative of future performance due to fluctuating commodity prices, receipt of regulatory decisions, the performance and retirement of existing generation facilities and the addition of new generation facilities.

ENMAX's core operations include the competitive generation and sale of electricity across Alberta through ENMAX Energy and the regulated transmission and distribution of electricity in the City of Calgary through ENMAX Power. ENMAX Corporate provides billing and customer care services, shared services and financing to ENMAX Energy and ENMAX Power.

SIGNIFICANT EVENTS AND TRANSACTIONS

GREENHOUSE GAS EMISSIONS

On June 25, 2015, the Alberta government announced plans to revise the province's climate change strategy. The first stage involves changes to Alberta's Specified Gas Emitters Regulation (SGER) to achieve reduction in Alberta's greenhouse gas emissions. The second stage is a review of the province's broader climate change policy. SGER sets emission intensity limits for facilities producing at least 100,000 tonnes of carbon dioxide. The announcement increased the required emission intensity improvements from 12 percent to 15 percent in 2016 and to 20 percent in 2017, along with an increase in compliance cost on every tonne that does not meet the improvement target from $15 per tonne to $20 per tonne in 2016 and $30 per tonne in 2017. The review of the province's climate change policy, which will include relevant stakeholders, is expected to be completed in the fall of 2015. This review will lead to the announcement of Alberta's Climate Change Strategy.

DIVIDEND

On March 19, 2015, the Corporation declared a dividend of $56.0 million payable to The City in quarterly installments throughout 2015.

SHEPARD ENERGY CENTRE

On March 11, 2015, Shepard was declared fully operational. Designed to generate over 800 MW of electricity and fuelled by natural gas, the facility is the largest of its kind in the province and an important step in Alberta's transition away from aging coal-fired generation facilities. First announced by ENMAX in 2007, the project became a joint arrangement when Capital Power agreed to become a 50 percent owner in late 2012.

ENMAX ENERGY

STRATEGY

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.

The core strategy for ENMAX Energy is to grow its customer base across Alberta and invest in power generation facilities required to serve electricity customers. ENMAX Energy supplies electricity through its own wind and natural-gas-fuelled generation facilities and power purchase arrangements (PPAs) at Battle River and Keephills. It balances energy portfolio requirements through the purchase and sale of electricity and natural gas from and into wholesale Alberta markets. The remaining power and all natural gas required to meet ENMAX Energy's consumer electricity and natural gas demand is acquired through the competitive wholesale power and natural gas markets. During times when ENMAX Energy has excess generation capacity, energy is sold to the market. ENMAX Energy provides customers with competitive energy products and services with a focus on longer-term fixed electricity contracts. These contracts link customer demand to generating assets, which results in relatively stable margins, even during times of volatile wholesale electricity prices.

BUSINESS UPDATE

On March 11, 2015, the Keephills Unit 1 was producing near capacity when it was required to unexpectedly come offline. The unit returned to service on May 21, 2015. The plant owner has claimed "force majeure" for this outage. 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 Shepard Energy Centre experienced an unplanned outage in Q2, 2015. Available capacity for the facility was reduced in late May and the majority of June as a result of the outage. Shepard was back on line with full available capacity as of June 25, 2015.

As at June 30, 2015, ENMAX Energy's capacity ownership interest is 2,750 MW of electricity generation to supply customer demands.

KEY BUSINESS STATISTICS	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Plant availability (%) (1)	**83.35**	94.52	**84.50**	96.89
Average flat pool price ($/MWh)	**57.25**	42.30	**43.20**	52.02

(1) Plant availability includes planned maintenance and forced outages. Without incorporating the Shepard heat recovery steam generator (HRSG) outage, plant availability for the three and six months ended June 30, 2015 was 98.59% and 96.99%, respectively.

In the three months ended June 30, 2015, ENMAX Energy experienced an increase in the average flat pool price from 2014 levels. This is attributable to plant outages in the market during this period that resulted in decreased supply in Alberta.

In the six months ended June 30, 2015, ENMAX Energy experienced a decrease in the average flat pool price from 2014 levels. This is attributable to lower settled power pool prices resulting from increased supply in the market.

ENMAX POWER

STRATEGY

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 Calgary's growing demand.

BUSINESS UPDATE

ENMAX Power filed the 2014–2015 Transmission General Tariff Application and 2014 Phase I Distribution Tariff Application with the Alberta Utilities Commission (AUC) in July 2013. An oral hearing occurred in July 2014, and ENMAX Power received the AUC decision (Decision 2014-347) in the fourth quarter of 2014. Pursuant to Decision 2014-347, ENMAX Power was required to file the compliance filing by February 10, 2015. The decision on the compliance filing was received on August 11, 2015.

ENMAX Power is preparing an application that will ultimately be used to establish 2015–2017 rates for distribution. On May 8, 2015, the AUC issued a bulletin that initiated a generic proceeding to establish parameters for the next generation of performance-based regulation (PBR) plans commencing January 1, 2018. In the bulletin, the AUC stated that it will explore how a PBR plan for ENMAX Power could be aligned with the second generation plans for the remaining distribution utilities commencing in 2018. In 2016, ENMAX Power expects to file an application to set its transmission revenue requirements for 2016 and 2017.

On April 30, 2015, the AUC issued a letter initiating the 2016 Generic Cost of Capital (GCOC) proceeding. The GCOC process has been established to determine the approved return on equity (ROE) and deemed equity ratios, which are also referred to as the capital structure, for all Alberta electric and gas utilities. A pre-proceeding process to establish the scope and a roundtable discussion to explore ways in which the hearing process may be streamlined is expected to occur in September 2015.

KEY BUSINESS STATISTICS	Three Months Ended June 30		Six Months Ended June 30	
	2015	2014	2015	2014
Distribution volumes (GWh)	2,234	2,279	4,658	4,742
System average interruption duration index (SAIDI) (1)			0.17	0.20
System average interruption frequency index (SAIFI) (2)			0.22	0.51

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

Total electricity delivered in the Calgary service area for the second quarter of 2015 was slightly lower than prior periods. Electricity volumes of 2,234 Gigawatt hours (GWh) were delivered during the three months ended June 30, 2015, compared to 2,279 GWh in the same period of 2014. For the six months ended June 30, 2015, total electricity delivered in the Calgary service area decreased from the same period in the prior year with electricity volumes delivered of 4,658 GWh compared with 4,742 GWh in the same period in 2014. The decrease was primarily due to lower demand as a result of a relatively warm winter.

SAIFI results for six months ended June 30, 2015 are improved over the prior comparative period as ENMAX Power experienced fewer outages in the six months ended June 30, 2015.

FINANCIAL RESULTS

UNUSUAL ITEM: 2014 PPA OUTAGES—KEEPHILLS UNIT 2

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 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 anticipates entering into a dispute resolution process with TransAlta in accordance with the terms of the PPA. For the three and six months ended June 30, 2014, the Keephills Unit 2 outage impact was nil and $17.4 million, respectively.

EBIT COMPARED WITH THE SAME PERIODS IN 2014

For the three months ended June 30 *(millions of dollars)*	ENMAX Energy	ENMAX Power	ENMAX Corporate	Consolidated
EBIT for the three months ended June 30, 2014	38.3	33.1	2.2	73.6
Decisions impacting prior year included in transmission and distribution margin:				
2014 Recovery of earnings on capital(1)	-	(13.5)	-	(13.5)
	38.3	19.6	2.2	60.1
Increased (decreased) margins attributable to:				
Electricity	(21.1)	(0.9)	0.2	(21.8)
Natural gas	1.9	-	(0.1)	1.8
Transmission and distribution(2)	-	4.7	-	4.7
Contractual services and other	(0.6)	0.6	0.6	0.6
Decreased (increased) expenses:				
Operation, maintenance & administration	(6.1)	1.5	(0.1)	(4.7)
Foreign exchange	2.7	-	-	2.7
Amortization	(10.8)	(1.0)	(2.3)	(14.1)
EBIT for the three months ended June 30, 2015	4.3	24.5	0.5	29.3

(1) AUC ruling received in the second quarter of 2014 approving recovery of earnings on transmission capital invested in prior periods.

(2) Transmission and distribution margins excluding decisions impacting prior year, as noted in above table.

For the six months ended June 30 *(millions of dollars)*	ENMAX Energy	ENMAX Power	ENMAX Corporate	Consolidated
EBIT for the six months ended June 30, 2014	78.2	54.0	2.9	135.1
Unusual items included in results:				
2014 Keephills Unit 2 outage	17.4	-	-	17.4
Decisions impacting prior year included in transmission and distribution margin:				
2014 Recovery of earnings on capital(1)	-	(13.5)	-	(13.5)
2014 Impact of Generic Cost of Capital (GCOC) decision(2)	-	(2.8)	-	(2.8)
	95.6	37.7	2.9	136.2
Increased (decreased) margins attributable to:				
Electricity, excluding 2014 Keephills Unit 2 outage	(12.2)	(0.5)	(0.4)	(13.1)
Natural gas	5.9	-	0.1	6.0
Transmission and distribution(3)	-	7.4	-	7.4
Contractual services and other	(1.2)	2.8	0.8	2.4
Decreased (increased) expenses:				
Operation, maintenance & administration	(12.3)	1.3	0.3	(10.7)
Foreign exchange	11.2	-	-	11.2
Amortization	(12.7)	(4.6)	(3.5)	(20.8)
EBIT for the six months ended June 30, 2015	74.3	44.1	0.2	118.6

(1) AUC ruling received in the second quarter of 2014 approving recovery of earnings on transmission capital invested in prior periods.

(2) On October 18, 2012, the AUC initiated the GCOC Proceeding. The GCOC Decision (Decision 2191-D01-2015) was issued on March 23, 2015, and sets out the approved ROE for all Alberta utilities for the years 2013, 2014 and 2015. It is estimated that this decision will result in an approximately $2.8 million revenue reduction ($2.2 million for distribution, $0.6 million for transmission) for 2014.

(3) Transmission and distribution margins excluding decisions impacting prior year, as noted in above table.

Normalized electricity margins, which exclude the 2014 Keephills Unit 2 outage, for the three months ended June 30, 2015 decreased $21.8 million to $82.2 million from $104.0 million in the same period in 2014. Normalized electricity margins for the six months ended June 30, 2015 decreased $13.1 million to $194.5 million compared with $207.6 million recorded in the same period in 2014.

The decreased electricity margins in the three and six months ended June 30, 2015 were primarily driven by higher settled pool price to supply electricity sales and lower realized sales prices on commercial fixed-price contracts. This higher cost was partially offset by both lower natural gas prices, which decreased the cost to run natural-gas-fuelled plants and higher volumes on commercial fixed-price contracts.

ENMAX acquired two natural-gas-fuelled electricity generation plants in the third quarter of 2014 and the Shepard Energy Centre began commercial operations in March 2015. These three facilities resulted in higher volumes generated to supply retail sales in the three and six months ended June 30, 2015, compared to the same periods in 2014. Lower natural gas input costs enabled ENMAX to capture a larger spread between contract selling prices and market prices. These increases were partially offset by realized losses on hedges and by lower than expected asset availability (PPAs and Shepard Energy Centre).

Natural gas margins for the three months ended June 30, 2015, increased $1.8 million to $8.5 million from $6.7 million for the three months ended June 30, 2014. Natural gas margins increased $6.0 million to $26.0 million for the six months ended June 30, 2015, compared with $20.0 million for the first half of 2014. The increase in the three and six months ended June 30, 2015, is primarily due to decreased purchase costs from lower gas market prices to supply customers. The lower costs were partially offset by lower sales volumes as a result of warmer temperatures in 2015.

For the three months ended June 30, 2015, transmission and distribution margins, excluding decisions impacting prior year, increased $4.7 million to $66.2 million compared to $61.5 million in the same period in 2014. Transmission and distribution margins increased $7.4 million to $133.8 million for the six months ended June 30, 2015, compared with $126.4 million for the six months ended June 30, 2014. The increase in transmission and distribution margins is due to an increase in interim rates in 2015. With respect to decisions impacting prior years, the three and six months ended June 30, 2015 increase in margin over the prior respective period excludes the $13.5 million impact of a prior year AUC ruling received in the second quarter of 2014 approving the recovery of earnings on transmission capital invested in prior periods. Additionally, the six months ended June 30, 2015, increase in margin excludes the GCOC decision received in March 2015, representing the $2.8 million 2014 reduction in earnings.

For the three months ended June 30, 2015, contractual services and other revenues increased $0.6 million to $18.4 million from $17.8 million in the second quarter of 2014. Contractual services margin and other revenue increased $2.4 million to $35.7 million in the six months ended June 30, 2015 from $33.3 million in the six months ended June 30, 2014. The increase for the six months ended June 30, 2015 is mainly attributable to increased activity on residential developer projects and increased revenue recognized from amortization of customer contributions for capital projects. The impact of this increase is partially offset by decreased construction activity related to Light Rail Transit (LRT) projects which were completed in 2014.

Operation, maintenance and administration (OM&A) for the three months ended June 30, 2015, increased $4.7 million to $86.2 million from $81.5 million in the three months ended June 30, 2014. OM&A expenses for the six months ended June 30, 2015, increased $10.7 million to $173.6 million compared with $162.9 million in the same period in 2014. The increase in the three and six months ended June 30, 2015 was due to staff and operating expenses related to the September 2014 acquisitions and Shepard becoming operational, and an increase in consulting costs related to other projects. These increases were partially offset by a decrease in costs related to billing and collections.

For the three months ended June 30, 2015, a net foreign exchange loss of $2.5 million was recognized compared to a loss of $5.2 million in the second quarter of 2014. For the six months ended June 30, 2015, ENMAX experienced a foreign exchange gain of $11.1 million, compared to a loss of $0.1 million in the same period in 2014. Foreign exchange gains or losses are primarily the result of net realized and unrealized gains and losses on long-term service agreements and equipment purchases denominated in foreign currencies and associated foreign exchange hedges.

Amortization expense for the three months ended June 30, 2015 was $57.3 million compared with $43.2 million in the same period in 2014. Amortization expense for the six months ended June 30, 2015 was $106.1 million, compared to $85.3 million in the first half of 2014. The increased charges were primarily the result of assets placed into service in 2015, which would include Shepard becoming operational on March 11, 2015 and the September 2014 acquisitions of the Cavalier Energy Centre and Balzac Power Station.

OTHER NET EARNINGS ITEMS

Finance charges increased $14.2 million to $20.2 million from $6.0 million for the three months ended June 30, 2015, compared to the three months ended June 30, 2014. For the six months ended June 30, 2015, finance charges decreased $4.1 million to $30.3 million from $34.4 million for the six months ended June 30, 2014. The increase in the three months ended June 30, 2015 was primarily due to the shift of interest costs being capitalized prior to Shepard being fully operational in March 2015 and increased interest costs resulting from the acquisition of new long-term debt. The decrease in the six months ended June 30, 2015 was due to the non-reoccurrence of $20.7 million of settlement costs associated with the termination of the interest rate swaps in the first quarter of 2014, partially offset by current period reduction of capitalized interest and acquisition of new long-term debt.

Current and deferred income tax costs for the three months ended June 30, 2015 decreased $13.0 million to a recovery of $11.2 million from an expense of $1.8 million for the same period in 2014. Current and deferred income tax costs for the six months ended June 30, 2015 decreased $0.5 million to a recovery of $2.4 million from a recovery of $2.9 million for the same period in 2014. The increase in income tax recovery for the quarter was primarily due to lower income in taxable entities combined with the increased tax rates for future years, increasing future tax recoveries. The six months ended June 30, 2015 showed a minor decrease in income tax recovery due to higher taxable earnings in the first quarter of 2015 substantially offset with the lower income and the change in the Alberta corporate tax rate (impact of $1.8 million) during the second quarter as compared to the prior periods.

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, 2015, OCI totalled gains of $29.5 million and $41.2 million respectively, compared with losses of $2.3 million and gains of $17.1 million respectively, for the same periods in 2014. OCI for the three and six months ended June 30, 2015 primarily reflects the fair value changes in electricity, natural gas and commodity positions and prior period settlement of interest rate swaps.

CORPORATE AND INTERSEGMENT ELIMINATIONS

ENMAX Corporate provides billing and customer care services shared services and financing to its subsidiaries ENMAX Power and ENMAX Energy. During the three and six months ended June 30, 2015, EBIT for ENMAX Corporate decreased to $0.5 million and $0.2 million respectively, as compared with $2.2 million and $2.9 million respectively, in the same periods in 2014.

SELECTED QUARTERLY FINANCIAL DATA

	2015		2014				2013 (2)	
(millions of dollars)	Second	First	Fourth	Third	Second	First	Fourth	Third
Total revenue	**713.5**	**806.4**	786.9	778.1	752.1	1,003.7	897.1	803.5
Operating margin (1)	**175.3**	**214.7**	185.1	182.4	190.0	197.3	232.4	149.9
EBIT (1)	**29.3**	**89.3**	42.6	59.7	73.6	61.5	101.6	30.1
Net earnings	**20.3**	**70.4**	41.0	39.5	65.8	37.8	88.3	20.7

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

(2) 2013 values have not been restated to IFRS and reflect results in accordance with Part V of the *CPA Canada Handbook*, "Pre-Changeover Accounting Standards."

Many variables must be considered regarding the seasonality of revenue, operating margin, EBIT and net earnings. In the second quarter of 2015, net earnings are lower than the same period in 2014 as a result of lower realized prices on fixed price contracts and increased amortization and financing charges due to Shepard becoming operational. In the first quarter of 2015, revenues decreased compared to the first quarter of 2014 as a result of lower prices; however, the increased net earnings reflect increased electricity margins, and in 2014 there was additional interest associated with the early repayment of debt. In the fourth quarter of 2014, there were decreases in total revenue, operating margin, EBIT and earnings compared to the fourth quarter of 2013. The decreases were mainly attributable to reductions in realized electricity and natural gas prices. In the second and third quarters of 2014, the operating margin increased due to greater availability of electricity from PPAs, compared to 2013 and the impact of rate increases, versus the comparative quarters in the prior year. In the first quarter 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 early repayment of debt. 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 generally 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. In contrast, 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 natural-gas-fuelled generation. Revenue levels tend to decline in the fall and spring due to unfavourable trends in natural gas prices and volumes during those times of year.

NON-IFRS FINANCIAL MEASURES

Non-IFRS financial measures for ENMAX are provided in the MD&A. These measures do not have any standard meaning prescribed by IFRS and may not be comparable to similar measures presented by other companies. The purpose of these financial measures and their reconciliation to IFRS financial measures are shown below. These non-IFRS measures are consistently applied in the previous period.

OPERATING MARGIN

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2015**	**2014**	**2015**	**2014**
Electricity margins	**82.2**	104.0	**194.5**	207.6
Natural gas margins	**8.5**	6.7	**26.0**	20.0
Transmission and distribution margins	**66.2**	61.5	**133.8**	126.4
Contractual services margins [(1)] and other revenue	**18.4**	17.8	**35.7**	33.3
Adjusted operating margin (non-IFRS financial measure)	**175.3**	190.0	**390.0**	387.3
Deduct:				
Unusual item: 2014 Keephills Unit 2 outage	**-**	-	**-**	17.4
2014 Recovery of earnings on capital	**-**	(13.5)	**-**	(13.5)
2014 Impact of GCOC decision	**-**	-	**2.8**	-
Operating margin (non-IFRS financial measure)	**175.3**	203.5	**387.2**	383.4
OM&A, foreign exchange, amortization, financing charges and income taxes	**155.0**	137.7	**296.5**	279.8
Net earnings (IFRS financial measure)	**20.3**	65.8	**90.7**	103.6

(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

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2015**	**2014**	**2015**	**2014**
EBITDA (non-IFRS financial measure)	**86.6**	116.8	**224.7**	220.4
Deduct:				
Amortization	**57.3**	43.2	**106.1**	85.3
Finance charges	**20.2**	6.0	**30.3**	34.4
Income tax expense (recovery)	**(11.2)**	1.8	**(2.4)**	(2.9)
Net earnings (IFRS financial measure)	**20.3**	65.8	**90.7**	103.6

EBITDA is a useful measure of business performance, as it provides an indication of the results generated by 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 2015	2014	Six Months Ended June 30 2015	2014
Operating profit (IFRS financial measure)	(11.2)	39.3	59.2	78.2
Adjustments for rate-regulated activities	40.5	34.3	59.4	56.9
EBIT (non-IFRS financial measure)	29.3	73.6	118.6	135.1
Deduct:				
Finance charges	20.2	6.0	30.3	34.4
Income tax expense (recovery)	(11.2)	1.8	(2.4)	(2.9)
Net earnings (IFRS financial measure)	20.3	65.8	90.7	103.6

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.

OTHER EXPENSES

(millions of dollars)	Three Months Ended June 30 2015	2014	Six Months Ended June 30 2015	2014
OM&A	86.2	81.5	173.6	162.9
Contractual services costs	19.6	18.2	39.2	31.7
Foreign exchange loss (gain)	2.5	5.2	(11.1)	0.1
Movement in regulatory deferral balances	(14.9)	(5.4)	(23.6)	(9.0)
Other expense (IFRS financial measure)	93.4	99.5	178.1	185.7

Other expense breakdown is a measure of business performance, as it provides various margin and cost analysis of business activities that management uses to make decisions.

FUNDS FROM OPERATIONS

(millions of dollars)	Three Months Ended June 30 2015	2014	Six Months Ended June 30 2015	2014
Cash provided by operating activities (IFRS financial measure)	186.9	181.1	317.9	252.1
Changes in non-cash working capital	(109.5)	(61.0)	(124.0)	(24.2)
Employee future benefits	0.9	1.3	(0.9)	1.6
Contributions in aid of construction	(0.1)	(11.9)	(9.7)	(21.7)
Amortization of customer contributions	3.2	2.6	6.6	5.3
Funds from operations (non-IFRS financial measure)	81.4	112.1	189.9	213.1

Funds from operations are used as an additional metric of cash flow without regard to changes in the Corporation's non-cash working capital and adjusted for contributions in aid of construction.

TOTAL FINANCE CHARGES

(millions of dollars)	Three Months Ended June 30 2015	Three Months Ended June 30 2014	Six Months Ended June 30 2015	Six Months Ended June 30 2014
Total interest cost (non-IFRS financial measure)	**20.0**	15.3	**38.2**	33.3
Capitalized interest	**(1.4)**	(11.2)	**(11.3)**	(23.1)
Other non-interest financing costs	**0.7**	1.2	**1.5**	2.1
Accretion expense	**0.4**	0.3	**0.9**	0.6
Pension expense	**0.5**	0.4	**1.0**	0.8
Interest expense, excluding interest rate swaps settlement	**20.2**	6.0	**30.3**	13.7
Interest rate swaps settlement	**-**	-	**-**	20.7
Finance charges (IFRS financial measure)	**20.2**	6.0	**30.3**	34.4

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, 2015	December 31, 2014	$ Change	% Change	Explanation for Change
ASSETS					
Cash and cash equivalents	**245.3**	16.7	228.6	1369%	Refer to Liquidity and Capital Resources Section.
Accounts receivable	**506.1**	542.8	(36.7)	(7%)	Decrease due to timing of receipts, decreased electricity sales on commercial fixed-price contracts and lower natural gas sales volumes.
Property, plant and equipment (PPE)	**3,897.7**	3,818.0	79.7	2%	General capital additions offset by amortization.
LIABILITIES AND SHAREHOLDER'S EQUITY					
Accounts payable	**451.8**	419.8	32.0	8%	Mainly attributable to higher pool prices and higher capital accruals, offset by lower operational accruals.
Dividend payable	**28.0**	-	28.0	100%	Dividend declared in March 2015 to be paid by the end of 2015.
Financial assets (liabilities) (1)	**10.9**	(51.0)	61.9	(121%)	Change in fair value of hedging instruments.
Long term debt (1)	**1,749.4**	1,610.3	139.1	9%	Receipt of $189.2 million in new Alberta Capital Financing Authority (ACFA) funding, offset by repayment of $19.9 million of non-recourse Kettles term financing and $30.2 million of regularly scheduled debt payments.

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

LIQUIDITY AND CAPITAL RESOURCES

TOTAL LIQUIDITY AND CAPITAL RESERVES

As at *(millions of dollars)*	June 30, 2015	December 31, 2014
Committed and available bank credit facilities	**850.0**	1,150.0
Letters of credit issued:		
Power pool purchases	**111.8**	65.3
Energy trading	**49.0**	37.5
Regulatory commitments	**87.3**	87.5
Asset commitments	**1.5**	2.0
PPAs	**56.6**	56.7
	306.2	249.0
Overdraft facilities	**-**	27.3
Remaining available bank facilities	**543.8**	873.7
Cash on hand	**245.3**	16.7
Total liquidity and capital reserves	**789.1**	890.4

The decrease in total liquidity and capital reserves for the six months ended June 30, 2015, is attributed primarily to the reduction in available credit facilities partially offset by the increase in cash on hand. Total unsecured credit facilities were reduced by $300.0 million to $850.0 million on March 8, 2015.

CAPITAL STRATEGY

The business is funded with a view to maintaining a conservative capital structure in line with ENMAX's strategy of maintaining a stable, investment grade credit rating. ENMAX has set long-term target ratios for long-term debt to total capitalization at a maximum of 45.0 percent, and as at June 30, 2015, the long-term debt to total capitalization ratio is 42.6 percent (December 31, 2014 – 41.4 percent). 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 while 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 ENMAX's credit facilities is debt to capitalization. As at June 30, 2015, ENMAX is in compliance with all of the financial covenants in its debt agreements.

CASH PROVIDED BY OPERATING ACTIVITIES

Funds from operations for the three and six months ended June 30, 2015 were $81.4 million and $189.9 million respectively, compared with $112.1 million and $213.1 million respectively, in the same periods in 2014. For the three and six months ended June 30, 2015 the decreased funds generated period-over-period were primarily due to lower net earnings on account of lower electricity margins, lower transmission and distribution margins, and increased OM&A. Funds from operations exclude the impact of the increase in amortization expense as a result of Shepard being fully operational and the acquisition of Cavalier and Balzac in the latter half of 2014.

Cash provided by operating activities for the three months ended June 30, 2015 was $186.9 million compared to $181.1 million in the same period in 2014. For the six months ended June 30, 2015, cash provided by operations increased to $317.9 million from $252.1 million in the same period in 2014. The increase in the three and six months ended June 30, 2015 was driven by the increase in accounts payable partially offset by decrease of accounts receivable, which was lower due to timing of payments.

INVESTING ACTIVITIES

The following table outlines investment in capital additions for the three and six months ended June 30, 2015.

CAPITAL ADDITIONS *(millions of dollars)*	**Three Months Ended June 30**	**Six Months Ended June 30**
Residential and non-residential developments	11.5	26.3
AESO required capital projects	17.1	22.1
System infrastructure	8.5	15.4
Asset replacement & modification	16.0	29.5
Information technology, facilities and tools	6.5	11.6
ENMAX Power	59.6	104.9
Shepard	-	44.0
Other	5.8	14.8
ENMAX Energy	5.8	58.8
Other	1.7	4.9
Total	67.1	168.6

During the three months ended June 30, 2015, ENMAX continued to execute its capital plans to meet the increasing need for electricity in Calgary.

FINANCING ACTIVITIES

ENMAX made regularly scheduled long-term debt principal payments of $23.1 million and $30.2 million respectively, during the three and six months ended June 30, 2015, compared with $20.9 million and $27.7 million in the same periods in 2014.

At June 30, 2015, cash and cash equivalents amounted to $245.3 million, compared with $16.7 million at December 31, 2014. At June 30, 2015, there was no commercial paper consistent with commercial paper outstanding at December 31, 2014, and nil of overdraft on bank accounts compared with $27.3 million of overdrafts on bank accounts at December 31, 2014.

On March 19, 2015, ENMAX declared a dividend of $56.0 million payable to The City in quarterly installments throughout 2015. All quarterly installments of this dividend will be paid by the end of 2015. ENMAX has historically paid The City annual dividends of at least the higher of 30 percent of the prior year's net earnings or $30 million.

On March 12, 2015, ENMAX's unsecured credit facilities were amended. The total unsecured credit facilities were reduced by $300.0 million to $850.0 million, with $600.0 million in bilateral credit facilities and $250.0 million of syndicated credit facilities.

On July 20, 2015, the terms of the credit facilities were extended by one year. The letter of credit tranches in the amount of $300.0 million expire July 20, 2018 and the operating tranches in the amount of $550.0 million expire July 20, 2020.

On June 1, 2015, ENMAX repaid the outstanding principal of non-recourse Kettles Hill Wind Farm term financing. The carrying amount of the debt was $19.9 million.

FUTURE ACCOUNTING CHANGES

The following standards and interpretations are not yet effective and have not been applied in preparing these financial statements.

IFRS 9 (JULY 2014) FINANCIAL INSTRUMENTS

The final standard replaces IAS 39 Financial Instruments: Recognition and Measurement and previous versions of IFRS 9. The entire standard provides guidance and requirements on classification and measurement of financial assets and liabilities, impairment and hedging. The standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Corporation is currently assessing the impact of adopting this standard.

IFRS 15 REVENUE FROM CONTRACTS WITH CUSTOMERS

The new standard provides a framework that replaces existing revenue recognition guidance. Entities will apply a five-step model to determine when to recognize revenue and at what amount. The model specifies that revenue should be recognized when (or as) an entity transfers control of goods or services to a customer at the amount to which the entity expects to be entitled. The standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Corporation is currently assessing the impact of adopting this standard.

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of ENMAX's 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.

ENMAX's 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 ENMAX's financial position or results of operations. These critical estimates are described in the 2014 Financial Report in the Critical Accounting Estimates section of the MD&A and in Note 3 of the Condensed Consolidated Interim Financial Statements.

RISK MANAGEMENT AND UNCERTAINTIES

ENMAX's approach to risk management addresses risk exposures across all of the Corporation's business activities and risk types. ENMAX uses 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. ENMAX's 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 ENMAX's 2014 Financial Report.

FINANCIAL INSTRUMENTS

In conducting its operations, ENMAX uses various instruments, including forwards, futures, swaps and options to reduce its market risks. Refer to Note 5 in the Notes to the Condensed Consolidated Interim Financial Statements for further information on financial instruments.

ASSET RETIREMENT OBLIGATIONS

At June 30, 2015, asset retirement obligations exist relating to the following generating assets: McBride, Taber, Kettles, Crossfield, Calgary Energy Centre, Cavalier, Balzac and Shepard. The accretion expense on these assets is included in finance charges in the Condensed Consolidated Interim Statements of Earnings and Comprehensive Income. These critical obligations are described in Note 10 of the Condensed Consolidated Interim Financial Statements.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate," "plan," "estimate," "expect," "may," "will," "intend," "should," and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Corporation believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct, and such forward-looking information should not be unduly relied upon.

CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS

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CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

As at *(unaudited)* *(millions of Canadian dollars)*		**June 30, 2015**		**December 31, 2014** *(Note 20)*
ASSETS				
Cash and cash equivalents	$	245.3	$	16.7
Accounts receivable		506.1		542.8
Income taxes receivable		103.5		96.8
Current portion of financial assets (Note 5)		91.7		53.6
Other current assets (Note 7)		41.1		26.9
		987.7		736.8
Property, plant and equipment (Note 8)		3,897.7		3,818.0
Power purchase arrangements		215.9		235.5
Intangible assets		137.8		128.9
Deferred income tax assets		58.4		58.2
Financial assets (Note 5)		60.9		14.5
Other long-term assets (Note 7)		17.8		20.2
TOTAL ASSETS		5,376.2		5,012.1
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES (Note 6)		39.0		66.6
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	$	5,415.2	$	5,078.7
LIABILITIES				
Short-term debt (Note 9)	$	-	$	27.3
Accounts payable and accrued liabilities		451.8		419.8
Dividend payable (Note 15)		28.0		-
Income taxes payable		-		0.6
Current portion of long-term debt (Note 5)		69.6		62.6
Current portion of financial liabilities (Note 5)		101.0		95.8
Current portion of deferred revenue (Note 11)		5.0		12.1
Other current liabilities (Note 7)		75.4		31.2
		730.8		649.4
Long-term debt (Note 5)		1,679.8		1,547.7
Deferred income tax liabilities		78.5		65.5
Post-employment benefits		57.3		56.4
Financial liabilities (Note 5)		40.7		23.3
Deferred revenue (Note 11)		370.7		360.5
Other long-term liabilities (Note 7)		29.8		34.4
Asset retirement obligations (Note 10)		58.7		57.9
TOTAL LIABILITIES		3,046.3		2,795.1
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES (Note 6)		11.9		2.5
SHAREHOLDER'S EQUITY				
Share capital		280.1		280.1
Retained earnings		2,084.9		2,050.2
Accumulated other comprehensive loss (Note 12)		(8.0)		(49.2)
		2,357.0		2,281.1
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY	$	5,415.2	$	5,078.7

Commitments and contingencies (Note 19)
See accompanying Notes to Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF EARNINGS

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
(unaudited) *(millions of Canadian dollars)*	**2015**	**2014 (Note 20)**	**2015**	**2014 (Note 20)**
REVENUE (Note 4)				
Electricity	506.7	502.1	1,014.5	1,119.8
Natural gas	63.7	100.5	209.0	331.4
Transmission and distribution	92.9	88.8	191.5	182.9
Local access fees	27.7	30.9	54.0	66.6
Other revenue (Note 13)	22.5	29.8	50.9	55.1
TOTAL REVENUE	713.5	752.1	1,519.9	1,755.8
OPERATING EXPENSES (Note 4)				
Electricity and fuel purchases	424.3	398.2	819.5	929.6
Natural gas and delivery	55.2	93.8	183.0	311.4
Transmission and distribution	66.8	47.2	120.0	99.0
Local access fees and grid charges	27.7	30.9	54.0	66.6
Depreciation and amortization	57.3	43.2	106.1	85.3
Other expenses (Note 13)	93.4	99.5	178.1	185.7
TOTAL OPERATING EXPENSES	724.7	712.8	1,460.7	1,677.6
OPERATING PROFIT (LOSS)	(11.2)	39.3	59.2	78.2
Finance charges	20.2	6.0	30.3	34.4
NET EARNINGS (LOSS) BEFORE TAX	(31.4)	33.3	28.9	43.8
Current income tax expense (recovery)	(9.2)	0.6	(1.9)	1.5
Deferred income tax expense (recovery)	(2.0)	1.2	(0.5)	(4.4)
NET EARNINGS (LOSS)—BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES	(20.2)	31.5	31.3	46.7
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES (Note 6)	40.5	34.3	59.4	56.9
NET EARNINGS	20.3	65.8	90.7	103.6

See accompanying Notes to the Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME

(unaudited) *(millions of Canadian dollars)*	THREE MONTHS ENDED JUNE 30 2015	THREE MONTHS ENDED JUNE 30 2014 (Note 20)	SIX MONTHS ENDED JUNE 30 2015	SIX MONTHS ENDED JUNE 30 2014 (Note 20)
NET EARNINGS	20.3	65.8	90.7	103.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX				
Unrealized gain (loss) on derivatives designated as available-for-sale financial assets includes deferred income tax expense of $nil for the three- and six-month periods, respectively (2014—$nil tax expense)	(0.1)	0.1	(0.1)	0.1
Unrealized gain (loss) on derivatives designated as cash flow hedges, includes deferred income tax expense of $9.3 and $10.4 for the three-and six-month periods, respectively (2014—$4.5 and $9.1 tax expense)	25.6	7.8	26.7	35.5
Realized losses (gains) on derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current year; includes deferred income tax benefit of $1.0 and $2.3 for the three- and six-month periods, respectively (2014—$3.1 and $4.5 tax expense)	4.0	(10.2)	14.6	(18.5)
Other comprehensive income (loss), net of income tax	29.5	(2.3)	41.2	17.1
TOTAL COMPREHENSIVE INCOME	49.8	63.5	131.9	120.7

See accompanying Notes to the Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

(unaudited) *(millions of Canadian dollars)*	**Share Capital**	**Retained Earnings**	**Accumulated Other Comprehensive Income (Loss)**	**Total**
As at January 1, 2015	280.1	2,050.2	(49.2)	2,281.1
Net earnings	-	70.4	-	70.4
Dividends declared	-	(56.0)	-	(56.0)
Other comprehensive income, net of income tax	-		11.7	11.7
As at March 31, 2015	280.1	2064.6	(37.5)	2,307.2
Net earnings	-	20.3	-	20.3
Other comprehensive income, net of income tax	-	-	29.5	29.5
As at June 30, 2015	280.1	2,084.9	(8.0)	2,357.0
As at January 1, 2014	280.1	1,926.1	(7.4)	2,198.8
Net earnings	-	37.8	-	37.8
Dividends declared	-	(60.0)	-	(60.0)
Other comprehensive income, net of income tax	-	-	19.4	19.4
As at March 31, 2014	280.1	1,903.9	12.0	2,196.0
Net earnings	-	65.8	-	65.8
Other comprehensive loss, net of income tax	-	-	(2.3)	(2.3)
As at June 30, 2014 (Note 20)	280.1	1,969.7	9.7	2,259.5

See accompanying Notes to the Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF CASH FLOWS

(unaudited) (millions of Canadian dollars)	THREE MONTHS ENDED JUNE 30 2015	2014	SIX MONTHS ENDED JUNE 30 2015	2014
CASH PROVIDED BY (USED IN):				
OPERATING ACTIVITIES				
Net earnings	20.3	65.8	90.7	103.6
Contributions in aid of construction	0.1	11.9	9.7	21.7
Amortization of customer contributions	(3.2)	(2.6)	(6.6)	(5.3)
Other items not involving cash (Note 16)	61.1	46.3	99.2	109.5
	78.3	121.4	193.0	229.5
Change in non-cash working capital (Note 17)	109.5	61.0	124.0	24.2
Post-employment benefits	(0.9)	(1.3)	0.9	(1.6)
Cash flow from operating activities	186.9	181.1	317.9	252.1
INVESTING ACTIVITIES				
Purchase of property, plant and equipment	(77.5)	(100.1)	(171.0)	(205.0)
Other assets	(0.8)	(0.4)	2.4	11.7
Cash flow used in investing activities	(78.3)	(100.5)	(168.6)	(193.3)
FINANCING ACTIVITIES				
Repayment of short-term debt	(89.9)	(982.6)	(247.2)	(1,142.5)
Proceeds of short-term debt	59.2	741.7	219.9	1,142.5
Proceeds of long-term debt	189.2	232.1	189.2	232.1
Repayment of long-term debt and interest rate swaps	(42.9)	(20.8)	(50.0)	(264.3)
Dividend paid	(14.0)	(15.0)	(28.0)	(30.0)
Other long-term liabilities	(3.3)	(0.2)	(4.6)	(0.8)
Cash flow provided by (used in) financing activities	98.3	(44.8)	79.3	(63.0)
Increase (decrease) in cash and cash equivalents	206.9	35.8	228.6	(4.2)
Cash and cash equivalents, beginning of period	38.4	40.6	16.7	80.6
CASH AND CASH EQUIVALENTS, END OF PERIOD	245.3	76.4	245.3	76.4
Supplementary information:				
Interest paid	33.1	26.9	36.3	33.1
Income taxes paid	2.0	3.5	4.8	5.1
Cash and cash equivalents consist of:				
Cash	85.8	75.7	85.8	75.7
Short-term investments	159.5	0.7	159.5	0.7

See accompanying Notes to Condensed Consolidated Interim Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS (UNAUDITED)

1. DESCRIPTION OF THE BUSINESS

ENMAX Corporation (ENMAX or the Corporation), a wholly owned subsidiary of The City of Calgary (The City), was incorporated under the Business Corporation Act (Alberta) in July 1997 to carry on the electric utility transmission and distribution operations previously carried on by the Calgary Electric System (CES), a former department of The City. Operations of the Corporation began on January 1, 1998 with the transfer of substantially all of the assets and liabilities of the CES by The City into the Corporation at net book value for consideration of one common share issued to The City. The Corporation's registered and head office is at 141 - 50 Ave SE, Calgary, AB, T2G 4S7. The Corporation's principal place of business is Alberta.

2. BASIS OF PREPARATION AND ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Condensed Consolidated Interim Financial Statements (the "financial statements") have been prepared by management in accordance with International Financial Reporting Standards (IFRS) as set out in Part I of the Canadian Professional Accountants Handbook (CPA Handbook). In 2010, the CPA Handbook was revised to incorporate IFRS and required publicly accountable enterprises to apply such standards for years beginning on or after January 1, 2011. However, several deferral options were made available to entities that had activities subject to rate regulation. The Corporation was eligible for the deferral options and elected to take those options. Accordingly, the Corporation's transition date to IFRS was January 1, 2014, and results for each of the periods from January 1, 2014, to December 31, 2014, have been restated from the pre-changeover accounting standards in Part V of the CPA Handbook, "Canadian Generally Accepted Accounting Principles" (Canadian GAAP), to IFRS.

These financial statements have been prepared in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards," and with International Accounting Standard (IAS) 34, "Interim Financial Reporting," and do not contain all disclosures required for the preparation of annual financial statements. Accordingly, the Condensed Consolidated Interim Financial Statements should be read in conjunction with ENMAX's Consolidated Financial Statements for the year ended December 31, 2014 prepared in accordance with Canadian GAAP as well as the Corporation's March 31, 2015 Condensed Consolidated Interim Financial Statements prepared in accordance with IFRS. The Corporation's March 31, 2015 Condensed Consolidated Interim Financial Statements include certain disclosures not repeated in the June 30, 2015 Condensed Consolidated Interim Financial Statements, including disclosure of IFRS 1 elections made by the Corporation, the Corporation's significant accounting policies in accordance with IFRS and the Corporation's use of judgments and estimates.

BASIS OF MEASUREMENT

These financial statements have been prepared on the historical cost basis except for the revaluation of financial derivative instruments to fair value.

FUNCTIONAL AND PRESENTATION CURRENCY

These financial statements are presented in millions of Canadian dollars, which is the Corporation's functional currency.

3. ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

The following standards and interpretations are not yet effective and have not been applied in preparing these financial statements.

IFRS 9 (July 2014) *Financial Instruments*

The final standard replaces IAS 39 Financial Instruments: Recognition and Measurement and previous versions of IFRS 9. The entire standard provides guidance and requirements on classification and measurement of financial assets and liabilities, impairment and hedging. The standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Corporation is currently assessing the impact of adopting this standard.

IFRS 15 *Revenue from Contracts with Customers*

The new standard provides a framework that replaces existing revenue recognition guidance. Entities will apply a five-step model to determine when to recognize revenue and at what amount. The model specifies that revenue should be recognized when (or as) an entity transfers control of goods or services to a customer at the amount to which the entity expects to be entitled. The standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Corporation is currently assessing the impact of adopting this standard.

4. SEGMENT INFORMATION

The Corporation operates in two segments representing separately managed business units, each of which offers different products and services.

ENMAX ENERGY

ENMAX Energy is an operating segment established to carry out competitive energy supply and retail functions through various legal entities and affiliated companies.

ENMAX POWER

ENMAX Power is primarily a regulated segment established to carry out electricity transmission and distribution service functions and the regulated-rate option (RRO) retail function through various legal entities and affiliated companies. ENMAX Power also provides non-regulated engineering, procurement, construction and maintenance services.

Three months ended June 30, 2015 (millions of dollars)	ENMAX Energy	ENMAX Power	Corporate & Intersegment Eliminations	Adjusted Consolidated Totals	Adjustments for Rate Regulated Activities	Consolidated Totals
REVENUE						
Electricity	561.6	18.7	(73.8)	506.5	0.2	506.7
Natural gas	63.9	-	(0.2)	63.7	-	63.7
Transmission and distribution	-	95.1	-	95.1	(2.2)	92.9
Local access fees	-	27.7	-	27.7	-	27.7
Other revenue	5.8	30.1	2.1	38.0	(15.5)	22.5
TOTAL REVENUE	631.3	171.6	(71.9)	731.0	(17.5)	713.5
OPERATING EXPENSES						
Electricity and fuel purchases	483.9	13.9	(73.5)	424.3	-	424.3
Natural gas and delivery	55.2	-	-	55.2	-	55.2
Transmission and distribution	-	28.9	-	28.9	37.9	66.8
Local access fees and grid charges	-	27.7	-	27.7	-	27.7
Depreciation and amortization	35.0	19.6	2.7	57.3	-	57.3
Other expenses	52.9	57.0	(1.6)	108.3	(14.9)	93.4
TOTAL OPERATING EXPENSES	627.0	147.1	(72.4)	701.7	23.0	724.7
OPERATING PROFIT (LOSS)	4.3	24.5	0.5	29.3	(40.5)	(11.2)
Finance charges				20.2	-	20.2
NET EARNINGS (LOSS) BEFORE TAX				9.1	(40.5)	(31.4)
Current income tax recovery				(9.2)	-	(9.2)
Deferred income tax recovery				(2.0)	-	(2.0)
NET EARNINGS (LOSS) BEFORE NET MOVEMENT IN REGULATORY DEFERRAL BALANCES				20.3	(40.5)	(20.2)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	40.5	40.5
NET EARNINGS				20.3	-	20.3

Three months ended June 30, 2014 (millions of dollars)	ENMAX Energy	ENMAX Power	Corporate & Intersegment Eliminations	Adjusted Consolidated Totals	Adjustments for Rate Regulated Activities	Consolidated Totals
REVENUE						
Electricity	560.1	32.8	(90.7)	502.2	(0.1)	502.1
Natural gas	100.6	-	(0.1)	100.5	-	100.5
Transmission and distribution	-	100.4	-	100.4	(11.6)	88.8
Local access fees	-	30.9	-	30.9	-	30.9
Other revenue	6.1	28.4	1.5	36.0	(6.2)	29.8
TOTAL REVENUE	666.8	192.5	(89.3)	770.0	(17.9)	752.1
OPERATING EXPENSES						
Electricity and fuel purchases	461.3	27.1	(90.2)	398.2	-	398.2
Natural gas and delivery	93.8	-	-	93.8	-	93.8
Transmission and distribution	-	25.4	-	25.4	21.8	47.2
Local access fees and grid charges	-	30.9	-	30.9	-	30.9
Depreciation and amortization	24.2	18.6	0.4	43.2	-	43.2
Other expenses	49.2	57.4	(1.7)	104.9	(5.4)	99.5
TOTAL OPERATING EXPENSES	628.5	159.4	(91.5)	696.4	16.4	712.8
OPERATING PROFIT	38.3	33.1	2.2	73.6	(34.3)	39.3
Finance charges	35.4	7.5	(36.9)	6.0	-	6.0
NET EARNINGS BEFORE TAX	2.9	25.6	39.1	67.6	(34.3)	33.3
Current income tax expense				0.6	-	0.6
Deferred income tax expense				1.2	-	1.2
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL BALANCES				65.8	(34.3)	31.5
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES	-	-	-	-	34.3	34.3
NET EARNINGS				65.8	-	65.8

Six months ended June 30, 2015 (millions of dollars)	**ENMAX Energy**	**ENMAX Power**	**Corporate & Intersegment Eliminations**	**Adjusted Consolidated Totals**	**Adjustments for Rate Regulated Activities**	**Consolidated Totals**
REVENUE						
Electricity	1,129.1	47.5	(162.6)	1,014.0	0.5	1,014.5
Natural gas	209.5	-	(0.5)	209.0	-	209.0
Transmission and distribution	-	186.8	-	186.8	4.7	191.5
Local access fees	-	54.0	-	54.0	-	54.0
Other revenue	10.8	60.1	4.0	74.9	(24.0)	50.9
TOTAL REVENUE	1,349.4	348.4	(159.1)	1,538.7	(18.8)	1,519.9
OPERATING EXPENSES						
Electricity and fuel purchases	944.5	36.5	(161.5)	819.5	-	819.5
Natural gas and delivery	183.0	-	-	183.0	-	183.0
Transmission and distribution	-	55.8	-	55.8	64.2	120.0
Local access fees and grid charges	-	54.0	-	54.0	-	54.0
Depreciation and amortization	61.7	39.4	5.0	106.1	-	106.1
Other expenses	85.9	118.6	(2.8)	201.7	(23.6)	178.1
TOTAL OPERATING EXPENSES	1,275.1	304.3	(159.3)	1,420.1	40.6	1,460.7
OPERATING PROFIT	74.3	44.1	0.2	118.6	(59.4)	59.2
Finance charges				30.3	-	30.3
NET EARNINGS BEFORE TAX				88.3	(59.4)	28.9
Current income tax recovery				(1.9)	-	(1.9)
Deferred income tax recovery				(0.5)	-	(0.5)
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL BALANCES				90.7	(59.4)	31.3
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	59.4	59.4
NET EARNINGS				90.7	-	90.7

Six months ended June 30, 2014 (millions of dollars)	**ENMAX Energy**	**ENMAX Power**	**Corporate & Intersegment Eliminations**	**Adjusted Consolidated Totals**	**Adjustments for Rate Regulated Activities**	**Consolidated Totals**
REVENUE						
Electricity	1,237.6	70.2	(188.0)	1,119.8	-	1,119.8
Natural gas	332.0	-	(0.6)	331.4	-	331.4
Transmission and distribution	-	192.4	-	192.4	(9.5)	182.9
Local access fees	-	66.6	-	66.6	-	66.6
Other revenue	11.6	50.2	3.2	65.0	(9.9)	55.1
TOTAL REVENUE	1,581.2	379.4	(185.4)	1,775.2	(19.4)	1,755.8
OPERATING EXPENSES						
Electricity and fuel purchases	1,058.2	58.7	(187.3)	929.6	-	929.6
Natural gas and delivery	311.4	-	-	311.4	-	311.4
Transmission and distribution	-	52.5	-	52.5	46.5	99.0
Local access fees and grid charges	-	66.6	-	66.6	-	66.6
Depreciation and amortization	49.0	34.8	1.5	85.3	-	85.3
Other expenses	84.4	112.8	(2.5)	194.7	(9.0)	185.7
TOTAL OPERATING EXPENSES	1,503.0	325.4	(188.3)	1,640.1	37.5	1,677.6
OPERATING PROFIT	78.2	54.0	2.9	135.1	(56.9)	78.2
Finance charges				34.4	-	34.4
NET EARNINGS BEFORE TAX				100.7	(56.9)	43.8
Current income tax expense				1.5	-	1.5
Deferred income tax recovery				(4.4)	-	(4.4)
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL BALANCES				103.6	(56.9)	46.7
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	56.9	56.9
NET EARNINGS				103.6	-	103.6

5. FINANCIAL INSTRUMENTS, HEDGES AND RISK MANAGEMENT

The Corporation 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.

LIQUIDITY RISK

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

The following table details the remaining contractual maturities for the Corporation'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, 2015	December 31, 2014
Less than 1 year (includes accounts payable)	649.9	601.8
1–3 years	397.8	253.5
3–5 years	347.5	499.8
More than 5 years	1,301.3	1,035.6

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

CONTRACTUAL MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES

As at *(millions of dollars)*	June 30, 2015	December 31, 2014
Less than 1 year	101.3	95.8
1–3 years	30.2	15.3
3–5 years	7.4	4.9
More than 5 years	2.8	3.1

VALUATION OF DERIVATIVE ASSETS AND LIABILITIES

Financial derivative instruments are recorded on the statement of financial position at fair value. As at June 30, 2015, 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 statement of financial position, presented in the table below:

As at *(millions of dollars)*	June 30, 2015		December 31, 2014	
	Hedge Instruments	Non-Hedge Derivatives	Hedge Instruments	Non-Hedge Derivatives
Assets				
Current	84.5	7.2	41.7	11.9
Non-current	60.0	0.9	14.0	0.5
Liabilities				
Current	91.5	9.5	71.5	24.3
Non-current	38.0	2.7	23.3	-

Cash flow hedges are used to manage the variability of cash flows resulting from the purchase and sale of electricity and natural gas, and foreign exchange exposure. For cash flow hedges, changes in the fair value of the effective portion of the hedging derivative are accumulated in other comprehensive income (OCI) and recognized in net earnings during the periods when the variability in cash flows of the hedged item is realized. During the three- and six-months ended June 30, 2015, there was no impact (2014—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-month periods ended June 30, 2015, there was no impact to earnings (2014—nil and $11.2 million respectively) related to hedges that no longer qualified for hedge accounting. In 2014, the interest rate swap hedge was terminated upon repayment of Calgary Energy Centre (CEC) non-recourse term financing.

The Corporation estimates that, of the $8.0 million of losses reported in accumulated OCI as at June 30, 2015, losses of $7.0 million are expected to be realized within the next 12 months, which will be offset by long-term gains at market prices in effect at the time of settlement.

Non-hedge derivatives are classified at fair value through profit and loss and recognized at fair market value with changes in fair market value being recorded through earnings. In the three- and six-month periods ended June 30, 2015, there were losses of $5.1 million and gains of $8.0 million (2014—$1.3 million loss and $8.6 million gain) recorded in net 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 Corporation estimated the fair value of its long-term debt 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 for comparable entities.

CARRYING AMOUNTS AND FAIR VALUES OF LONG-TERM DEBT

As at *(millions of dollars)*	June 30, 2015 Carrying Amount	June 30, 2015 Fair Value	December 31, 2014 Carrying Amount	December 31, 2014 Fair Value
Long-term debt [(1)] consisting of:				
Debentures, with remaining terms of				
Less than 5 years	76.3	78.8	63.2	65.8
6–10 years	82.5	90.2	85.8	93.7
11–15 years	31.9	37.1	21.8	25.4
16–20 years	394.0	461.6	269.7	316.5
21–25 years	663.0	700.6	648.3	690.8
Private debentures				
Series 1 (6.15%)	298.7	336.1	298.5	339.8
Series 3 (3.81%)	198.6	205.1	198.5	201.5
Non-recourse Kettles Hill Wind Farm (Kettles) term financing	-	-	19.9	21.6
Promissory note	4.4	4.7	4.6	4.8
	1,749.4	1,914.2	1,610.3	1,759.9

(1) Includes current portion of $69.6 million (December 31, 2014—$62.6 million). Maturity dates range from October 2015 to June 2040.

As at June 30, 2015, the Corporation had repaid the outstanding principle of non-recourse Kettles term financing. The carrying amount of the debt was $19.9 million.

6. REGULATORY DEFERRAL BALANCES

The timing of recognition of certain regulatory debits, credits, revenues and expenses may differ from what is otherwise expected under IFRS for non-regulated operations. The Corporation has recorded the following regulatory debit and credit balances:

As at *(millions of dollars)*	January 1, 2014	Balances Arising in the Period	Recovery (Reversal)	Balance Sheet Adjustment	December 31, 2014	Balances Arising in the Period	Balance Sheet Adjustments	June 30, 2015	Expected Recovery/Reversal Period (months)
Accounts receivable (Note a)	41.5	101.1	-	(124.1)	18.5	64.2	(62.7)	20.0	2
Un-eliminated inter-company profit on underground residential development (Note b)	-	1.5	-	-	1.5	0.4	-	1.9	
Other regulatory debits (Note c)	42.2	21.1	(0.4)	(16.3)	46.6	1.5	(31.0)	17.1	6
Total regulatory deferral account debit balances	83.7	123.7	(0.4)	(140.4)	66.6	66.1	(93.7)	39.0	

As at *(millions of dollars)*	January 1, 2014	Balances Arising in the Period	Recovery (Reversal)	Balance Sheet Adjustments	December 31, 2014	Balances Arising in the Period	Balance Sheet Adjustments	June 30, 2015	Expected Recovery/ Reversal Period (months)
Other regulatory credits (Note d)	1.9	5.1	(4.5)	-	2.5	6.7	2.7	11.9	12
Total regulatory deferral account credit balances	1.9	5.1	(4.5)	-	2.5	6.7	2.7	11.9	

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event. Regulatory deferral debit balances 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 deferral credit balances 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) Accounts receivable

Accounts receivable represent a price-only deferral account for transmission charges from the Alberta Electric System Operator (AESO). In the absence of rate regulation and the interim standard, IFRS would require that actual costs be recognized as an expense when incurred.

(b) Inter-company profit on underground residential development

A subsidiary of the Corporation performs construction work for the regulated operations of ENMAX Power at a profit. 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 of distribution assets. In the absence of rate regulation and the interim standard, IFRS would require that intercompany profits be eliminated upon consolidation. Subsequent to the IFRS transition date, the impact of un-eliminated intercompany profits have been separately presented as regulatory deferral account debit balances in the statement of financial position and the statement of earnings.

(c) Other regulatory debits

Other regulatory debits primarily relate to the Alberta Utilities Commission (AUC) flow-through items and other costs that will be collected from customers via future rates such as access service charges. Timing of the decision on collection of these items can result in significant fluctuation in balances from year to year.

(d) Other regulatory credits

Other regulatory credits 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, the Corporation'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 that 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. Any impairment related to regulatory deferral account debit balances are recorded in the period in which the related regulatory decisions are received.

7. OTHER ASSETS AND LIABILITIES

As at *(millions of dollars)*	**June 30, 2015**	**December 31, 2014**
Other current assets		
Prepaid expenses	40.6	26.4
Inventory	0.5	0.5
	41.1	26.9
Other long-term assets		
Prepaid expenses	4.7	4.8
Long-term accounts receivable	3.0	7.3
Other	10.1	8.1
	17.8	20.2
Other current liabilities		
Onerous contract	1.8	1.0
Provisions	7.2	2.2
Deposits	66.4	28.0
	75.4	31.2
Other long-term liabilities		
Onerous contract	16.1	17.7
Long-term payables	13.7	16.7
	29.8	34.4

8. PROPERTY, PLANT AND EQUIPMENT

	Transmission, Distribution and Substation Equipment	Generation Facilities and Equipment	Construction in Progress	Buildings and Site Development	Tools, Systems and Equipment	Land	Capital Spares and Other	Vehicles	Government Grants	Total
Cost										
As at January 1, 2014	1,369.5	1,230.0	866.3	167.5	77.2	34.4	33.5	24.1	(20.0)	3,782.5
Additions	180.7	-	133.1	59.0	11.8	2.9	5.7	2.5	-	395.7
Acquisitions	-	232.3	-	-	-	-	-	-	-	232.3
Disposals	(6.0)	(0.4)	-	(1.3)	(1.8)	(0.4)	-	(1.7)	-	(11.6)
Transfers	-	2.3	-	-	-	-	-	-	-	2.3
As at December 31, 2014	1,544.2	1,464.2	999.4	225.2	87.2	36.9	39.2	24.9	(20.0)	4,401.2
Additions	80.8	901.0	(844.8)	9.3	4.2	0.8	8.7	0.1	-	160.1
Disposals	(1.9)	(0.1)	-	-	-	-	-	-	-	(2.0)
Transfers	-	(4.6)	-	-	-	-	-	-	-	(4.6)
As at June 30, 2015	1,623.1	2,360.5	154.6	234.5	91.4	37.7	47.9	25.0	(20.0)	4,554.7
Accumulated Depreciation										
As at January 1, 2014	(1.8)	(383.6)	-	(24.5)	(48.7)	-	-	(4.0)	2.3	(460.3)
Depreciation	(61.5)	(44.2)	-	(7.3)	(6.8)	-	-	(1.9)	0.7	(121.0)
Disposals	6.0	0.1	-	0.1	1.7	-	-	1.5	-	9.4
Impairment	-	(11.3)	-	-	-	-	-	-	-	(11.3)
As at December 31, 2014	(57.3)	(439.0)	-	(31.7)	(53.8)	-	-	(4.4)	3.0	(583.2)
Depreciation	(30.7)	(36.4)	-	(3.4)	(4.5)	-	-	(1.0)	0.3	(75.7)
Disposal	1.9	-	-	-	-	-	-	-	-	1.9
As at June 30 31, 2015	(86.1)	(475.4)	-	(35.1)	(58.3)	-	-	(5.4)	3.3	(657.0)
Net Book Value										
As at January 1, 2014	1,367.7	846.4	866.3	143.0	28.5	34.4	33.5	20.1	(17.7)	3,322.2
As at December 31, 2014	1,486.9	1,025.2	999.4	193.5	33.4	36.9	39.2	20.5	(17.0)	3,818.0
As at June 30, 2015	1,537.0	1,885.1	154.6	199.4	33.1	37.7	47.9	19.6	(16.7)	3,897.7

Real property, including land and buildings, with a carrying amount of $237.8 million as at June 30, 2015 (December 31, 2014—$230.3 million), was subject to a right of first refusal to purchase held by The City.

For the three- and six-months ended June 30, 2015, capitalized borrowing costs amounted to $1.4 million and $11.3 million respectively (2014—$11.2 million and $23.1 million), with capitalization rates ranging from 4.93 percent to 5.00 percent. Interest is capitalized based on the actual costs of debt used to finance the capital construction projects. Interest rates ranged from 0.90 percent to 6.31 percent (2014—1.03 percent to 6.31 percent).

9. SHORT-TERM DEBT

As at June 30, 2015, the Corporation has unsecured credit facilities amounting to $850.0 million (December 31, 2014—$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 $600.0 million in bilateral operating facilities and $250.0 million of syndicated credit facilities. As at June 30, 2015, $276.2 million (December 31, 2014—$219.0 million) of operating facilities and $30.0 million (December 31, 2014—$30.0 million) of syndicated facilities were used in support of outstanding letters of credit.

Short-term debt is comprised of commercial paper, bank overdrafts and bankers' acceptances. At June 30, 2015, the Corporation had no short-term debt (December 31, 2014—$27.3 million at an average interest rate of 3.00 percent).

10. ASSET RETIREMENT OBLIGATIONS

The Corporation has estimated the net present value of the decommissioning liabilities associated with ENMAX Energy based on a total undiscounted future liability of $199.4 million (December 31, 2014—$199.4 million). These payments are expected to be made between 2043 and 2071. The Corporation calculated the present value of the obligations using discount rates between 2.65 percent and 3.24 percent (December 31, 2014—between 2.65 percent and 3.24 percent) to reflect the market assessment of the time value of money as well as risks specific to the liabilities that have not been included in the cash flow estimates and an inflation rate of 2.10 percent (December 31, 2014—2.10 percent).

(millions of dollars)	
Balance at January 1, 2014	49.9
Liabilities assumed on acquisition	6.7
Accretion expense	1.3
Balance at December 31, 2014	57.9
Accretion expense	0.8
Balance at June 30, 2015	58.7

The Corporation has an obligation to decommission its electricity transmission and distribution assets in Alberta. Due to the timing and cost of such future decommissioning activities being unknown, these costs cannot be reasonably estimated. Accordingly, the Corporation is unable to estimate the fair value of this retirement obligation and has not recorded a provision in the financial statements.

11. DEFERRED REVENUE

Revenues arising from the recognition of contributions in aid of construction (CIAC) were $3.2 million and $6.6 million for the three- and six-month periods ended June 30, 2015, respectively (2014—$2.6 million and $5.3 million).

12. ACCUMULATED OTHER COMPREHENSIVE LOSS

As at *(millions of dollars)*	June 30, 2015	December 31, 2014
Net unrealized losses on derivatives designated as available-for-sale financial assets	(0.1)	-
Net unrealized gains (losses) on derivatives designated as cash flow hedges	5.7	(35.6)
Net actuarial losses on defined benefit plans	(13.6)	(13.6)
Accumulated other comprehensive losses, including deferred income tax expense of $5.0 million (December 31, 2014—recovery of $3.7 million)	(8.0)	(49.2)

13. OTHER REVENUE AND EXPENSES

OTHER REVENUE

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2015	2014	2015	2014
Contractual service	13.7	23.5	34.6	41.3
Interest and penalty revenue	3.0	2.6	5.3	5.4
Amortization of CIAC	3.2	2.6	6.6	5.3
Miscellaneous	2.6	1.1	4.4	3.1
	22.5	29.8	50.9	55.1

OTHER EXPENSES

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	2015	2014	2015	2014
Salaries and wages	56.8	55.1	121.4	115.2
Materials and supplies	3.0	5.2	7.2	10.5
Goods and services	18.8	17.5	35.3	30.9
Administrative and office expenses	2.1	2.3	3.2	5.0
Building expense	12.8	16.2	22.8	27.1
Vehicles and other	(2.7)	(1.9)	(0.7)	(3.2)
Foreign exchange losses (gains)	2.6	5.1	(11.1)	0.2
	93.4	99.5	178.1	185.7

14. JOINT ARRANGEMENTS

Significant joint operations included in the consolidated financial statements at June 30, 2015 are listed below.

Significant Joint Operations	Operating Jurisdiction	Ownership Percent	Principal Activity
McBride Lake Wind Facility	Canada	50%	Power Generation
Shepard Energy Centre	Canada	50%	Power Generation
Balzac Power Station	Canada	50%	Power Generation
Genesee 4 and 5	Canada	50%	Power Generation

15. DIVIDEND

On March 19, 2015, the Corporation declared a dividend of $56.0 million to The City (2014—$60.0 million). The dividend will be paid in equal quarterly installments during 2015.

16. ITEMS NOT INVOLVING CASH

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2015**	**2014**	**2015**	**2014**
Depreciation and amortization	57.3	43.2	106.1	85.3
Deferred income tax expense (recovery)	(2.0)	1.2	(0.5)	(4.4)
Change in unrealized market value of financial contracts	5.1	1.2	(8.0)	27.4
Other	0.7	0.7	1.6	1.2
Change related to operating activities	61.1	46.3	99.2	109.5

17. CHANGE IN NON-CASH WORKING CAPITAL

	Three months ended June 30		Six months ended June 30	
(millions of dollars)	**2015**	**2014**	**2015**	**2014**
Accounts receivable	35.4	142.4	36.7	71.7
Regulatory deferral account debit balance	(11.3)	(1.6)	27.6	30.0
Income taxes receivable	(11.6)	(3.3)	(6.7)	(4.2)
Other current assets	(3.4)	(14.7)	(14.2)	(14.8)
Accounts payable and accrued liabilities	57.2	(68.7)	27.7	(67.9)
Regulatory deferral account credit balances	2.4	6.3	9.3	8.1
Other current liabilities	40.8	0.6	44.2	1.3
Income taxes payable	-	-	(0.6)	-
Change related to operating activities	109.5	61.0	124.0	24.2

18. RELATED-PARTY TRANSACTIONS

The Corporation's related-party transactions comprise both revenues from and expenditures to The City. Total revenues received from The City for the three- and six-months ended June 30, 2015 were $27.2 million and $56.4 million respectively (2014—$24.9 million and $65.5 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. The Corporation has committed to a water supply agreement, whereby The City supplies a specified amount of water annually to facilitate Shepard operations.

As at June 30, 2015, amounts owing to the Corporation from The City for services provided were $19.6 million (December 31, 2014—$35.7 million). No allowance for doubtful accounts have been recognized on this receivable (December 31, 2014—nil).

Total expenditures for goods and services received from The City for the three- and six-months ended June 30, 2015 were $29.0 million and $56.7 million respectively (2014—$31.9 million and $68.9 million). Most of these expenditures were for local access fees for use of The City's rights-of-way, this cost is passed through the Corporation 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 finance lease agreement with The City for the use of its land and buildings. As at June 30, 2015, the assets under the finance lease were $4.0 million (December 31, 2014—$4.1 million), and the finance lease obligation was $4.5 million (December 31, 2014—$4.6 million).

The total amount of debt owed to The City was $1,247.7 million at June 30, 2015 (December 31, 2014—$1,088.8 million). Interest paid for the three- and six-month periods ended June 30, 2015 was $19.3 million and $21.5 million respectively (2014—$16.4 million and $18.9 million). Principal payments of $30.2 million were made during the six-month period ended June 30, 2015 (2014—$27.8 million). In addition, the Corporation is required to pay a management fee to The City of 0.25 percent on the average monthly outstanding debenture balance held by The City on behalf of the Corporation. The administration fee paid for the three- and six-months ended June 30, 2015 was $0.7 million and $1.4 million respectively (2014—$0.6 million and $1.2 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.

19. COMMITMENTS AND CONTINGENCIES

The Corporation has commitments including property, plant and equipment (PPE) capital expenditures and obligations under other agreements. The Corporation assesses for potential contingencies for regulatory requirements, legal claims, power purchase arrangements, income tax, environmental liabilities, letters of credit, director/officer indemnifications and other indemnifications. A detailed description of the Corporation's commitments and contingencies was provided in Note 15 of the Condensed Consolidated Interim Financial Statements for the period ended March 31, 2015. There have been no material changes to the amounts with the exception of one additional tolling arrangement.

Upon the commencement of Shepard operations, the Corporation is required to make capacity payments to Capital Power, in accordance the 20-year Energy Services Agreement (ESA), to purchase 300 megawatts (MW) of Capital Power's Shepard output for the first three years of the ESA term and 200 MW for the remaining 17 years of the ESA term. The tolling arrangement commits the Corporation to minimum future payments of $176.5 million.

20. TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

For all periods up to and including the year ended December 31, 2014, the Corporation prepared its financial statements in accordance with Canadian GAAP. The Corporation adopted IFRS on January 1, 2015 in accordance with IFRS 1. IFRS 1 requires that comparative financial information be provided. IFRS 1 also requires a first-time adopter to use the same accounting policies in its opening IFRS statement of financial position and for all subsequent periods presented in its first IFRS financial statements. The adoption of IFRS includes full retrospective application of all IFRS standards that are effective at the end of its first IFRS reporting period, which will be December 31, 2015. In order to facilitate an effective adoption of IFRS, there are a number of discretionary exemptions as well as mandatory exceptions from retrospective application of a number of IFRS standards.

Reconciliations of the Consolidated Statement of Financial Position and Shareholder's Equity at December 31, 2014 and January 1, 2014, including a description of the IFRS 1 mandatory and discretionary exemptions, were previously provided in the March 31, 2015 Condensed Consolidated Interim Financial Statements, and therefore, are not included in these Condensed Consolidated Interim Financial Statements.

Restatement of previous presented balances in the March 31, 2015 Condensed Consolidated Interim Financial Statements and accompanying notes.

During the period ended June 30, 2015, the Corporation identified a number of projects with contributions from customers which are intercompany in nature that should have been presented net against PPE rather than included as deferred revenue on conversion to IFRS. The restatement resulted in decrease in both PPE and deferred revenue on the Statements of Financial Position by $30.1 million as at March 31, 2015, $30.6 million as at December 31, 2014 and $9.1 million as at January 1, 2014.

As a result of this restatement, cash flow from CIAC increased by $0.4 million which was offset by increase in cash flow used in purchase of PPE of $0.4 million on the Statements of Cash Flows for the three months ended March 31, 2015. Cash flow from CIAC decreased by $21.5 million which was offset by decrease in cash flow used in purchase of PPE of $21.5 million on the Statement of Cash Flows for the year ended December 31, 2014.

The restatement did not result in significant impact to the Statements of Earnings.

It should be noted that the restatement did not impact the Corporation's Consolidated Financial Statements for the year ended December 31, 2014 prepared in accordance with Canadian GAAP.

I. Reconciliation of consolidated statement of financial position and shareholder's equity at June 30, 2014, from Canadian GAAP to IFRS:

June 30, 2014 *(millions of dollars)*	Notes	Canadian GAAP	Measurement Adjustments	Reclassification Adjustments	IFRS
ASSETS					
Cash and cash equivalents		76.4	—	—	76.4
Accounts receivable	(4)	560.0	—	(48.1)	511.9
Income taxes receivable		101.1	—	—	101.1
Deferred income tax assets	(1)	6.1	—	(6.1)	—
Current portion of financial assets	(2)	—	(3.6)	42.6	39.0
Other current assets	(2)	70.1	0.7	(42.6)	28.2
		813.7	(2.9)	(54.2)	756.6
Property, plant and equipment	(a)(c)(d)(g)(4)(5)	3,132.4	(28.3)	346.5	3,450.6
Power purchase arrangements	(d) (e)	343.1	(87.8)	—	255.3
Intangible assets	(f)	127.5	(8.6)	—	118.9
Goodwill	(d)	16.0	(16.0)	—	—
Employee future benefits	(b)	23.5	(23.5)	—	—
Deferred income tax assets	(a)(c)(d)(e)(g)(h)(1)	44.0	7.7	6.1	57.8
Financial assets	(h)(2)	—	(1.4)	17.9	16.5
Other long-term assets	(2)(4)	36.6	—	(19.5)	17.1
TOTAL ASSETS		4,536.8	(160.8)	296.8	4,672.8
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	(4)	—	—	53.7	53.7
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES		4,536.8	(160.8)	350.5	4,726.5
LIABILITIES					
Accounts payable and accrued liabilities	(4)	363.0	—	(7.3)	355.7
Dividend payable		30.0	—	—	30.0
Deferred income tax liabilities	(1)	0.1	—	(0.1)	—
Current portion of long term debt		61.5	—	—	61.5
Current portion of financial liabilities	(3)	—	—	32.8	32.8
Current portion of deferred revenue		2.9	—	—	2.9
Other current liabilities	(g)(3)	52.6	2.5	(32.8)	22.3
		510.1	2.5	(7.4)	505.2
Long-term debt		1,381.1	—	—	1,381.1
Deferred income tax liabilities	(a)(c)(1)	82.8	(9.3)	0.1	73.6
Post-employment benefits	(b)	—	41.6	—	41.6
Financial liabilities	(3)	—	—	18.5	18.5
Deferred revenue	(5)	5.2	—	347.8	353.0
Other long-term liabilities	(g)(3)	25.2	26.8	(18.5)	33.5
Asset retirement obligations	(g)	15.6	34.9	—	50.5
TOTAL LIABILITIES		2,020.0	96.5	340.5	2,457.0
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES	(4)	—	—	10.0	10.0
SHAREHOLDER'S EQUITY					
Share capital		280.1	—	—	280.1
Retained earnings	(a) to (g)	2,225.9	(256.2)	—	1,969.7
Accumulated other comprehensive income	(h)	10.8	(1.1)	—	9.7
		2,516.8	(257.3)	—	2,259.5
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY		4,536.8	(160.8)	350.5	4,726.5

II. Reconciliation of total comprehensive income for the three months ended June 30, 2014, reported under Canadian GAAP to total comprehensive income reported under IFRS, being the comparative period:

Three months ended June 30, 2014 (millions of dollars)	Notes	Canadian GAAP	IFRS Adjustments	IFRS
REVENUE				
Electricity	(4)	502.2	(0.1)	502.1
Natural gas		100.5	—	100.5
Transmission and distribution	(4)	100.4	(11.6)	88.8
Local assess fees		30.9	—	30.9
Other revenues	(4)(5)	33.4	(3.6)	29.8
TOTAL REVENUE		767.4	(15.3)	752.1
OPERATING EXPENSES				
Electricity and fuel purchases		398.2	—	398.2
Natural gas and delivery		93.8	—	93.8
Transmission and distribution	(4)	25.4	21.8	47.2
Local access fees and grid charges		30.9	—	30.9
Depreciation and amortization	(a)(c)(d)(e)(f)(g)(5)	43.0	0.2	43.2
Other expenses	(a)(b)(g)(4)	105.9	(6.4)	99.5
TOTAL OPERATING EXPENSES		697.2	15.6	712.8
OPERATING PROFIT		70.2	(30.9)	39.3
Finance Charges	(b)(g)	5.3	0.7	6.0
NET EARNINGS BEFORE TAX		64.9	(31.6)	33.3
Current income tax expense		0.6	—	0.6
Deferred income tax expense	(a)(c)(d)(e)(g)(h)	0.7	0.5	1.2
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES		63.6	(32.1)	31.5
NET MOVEMENT IN REGULATORY DEFERRAL ACOUNT BALANCES	(4)	—	34.3	34.3
NET EARNINGS		63.6	2.2	65.8
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX				
Unrealized losses on available-for-sale financial assets arising during the year, includes deferred income tax of $nil.		0.1	—	0.1
Unrealized gain on derivatives designated as cash flow hedges, includes deferred income tax expense of $4.5.	(h)	7.8	—	7.8
Realized losses (gains)on derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current year, includes deferred income tax expense of $3.1		(10.2)	—	(10.2)
Other comprehensive income (loss), net of income tax		(2.3)	—	(2.3)
TOTAL COMPREHENSIVE INCOME		61.3	2.2	63.5

III. Reconciliation of total comprehensive income for the six months ended June 30, 2014, reported under Canadian GAAP to total comprehensive income reported under IFRS being the comparative period:

Six months ended June 30, 2014 (millions of dollars)	Notes	Canadian GAAP	IFRS Adjustments	IFRS
REVENUE				
Electricity	(4)	1,119.8	—	1,119.8
Natural gas		331.4	—	331.4
Transmission and distribution	(4)	192.4	(9.5)	182.9
Local assess fees		66.6	—	66.6
Other revenues	(4)(5)	59.7	(4.6)	55.1
TOTAL REVENUE		1,769.9	(14.1)	1,755.8
OPERATING EXPENSES				
Electricity and fuel purchases		929.6	—	929.6
Natural gas and delivery		311.4	—	311.4
Transmission and distribution	(4)	52.5	46.5	99.0
Local access fees and grid charges		66.6	—	66.6
Depreciation and amortization	(a)(c)(d)(e)(f)(g)(5)	84.8	0.5	85.3
Other expenses	(a)(b)(g)(4)	196.4	(10.7)	185.7
TOTAL OPERATING EXPENSES		1,641.3	36.3	1,677.6
OPERATING PROFIT		128.6	(50.4)	78.2
Finance charges	(b)(g)	33.0	1.4	34.4
NET EARNINGS BEFORE TAX		95.6	(51.8)	43.8
Current income tax expense		1.5	—	1.5
Deferred income tax recovery	(a)(c)(d)(e)(g)(h)	(5.4)	1.0	(4.4)
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCE		99.5	(52.8)	46.7
NET MOVEMENT REGULATORY DEFERRAL ACOUNT BALANCES	(4)	—	56.9	56.9
NET EARNINGS		99.5	4.1	103.6
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX				
Unrealized losses on available-for-sale financial assets arising during the year, includes deferred income tax of $nil.		0.1	—	0.1
Unrealized gain on derivatives designated as cash flow hedges, includes deferred income tax expense of $9.1.	(h)	35.5	—	35.5
Realized losses (gains) on derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current year, includes deferred income tax expense of $4.5.		(18.5)	—	(18.5)
Other comprehensive income, net of income tax		17.1	-	17.1
TOTAL COMPREHENSIVE INCOME		116.6	4.1	120.7

EXPLANATION OF THE MEASUREMENT ADJUSTMENTS IN THE TABLES ABOVE

(a) Property, plant and equipment (PPE)

(i) PPE (major overhaul and inspection costs)

Under Canadian GAAP, major overhauls and inspection costs are treated as a maintenance expense in the period the costs are incurred.

IFRS specifically requires that major overhauls and inspections, required at regular intervals to restore the condition of a fixed asset to continue to operate, be capitalized as a separate component and depreciated over the period to the next scheduled major inspection or overhaul.

Impact on the Corporation

On transition, historical major overhauls and inspection costs were capitalized, resulting in a prepaid expense increase of $0.4 million and a carrying value of PPE increase of $1.5 million, offset by a tax impact of $0.4 million. The net increase to opening retained earnings was $1.5 million on transition date.

As a result of this change, depreciation expense was higher by $0.9 million for the three-month period ended June 30, 2014, and $1.8 million for the six-month period ended June 30, 2014.

(ii) PPE (de-recognition)

Canadian GAAP does not specifically require the carrying amount of parts which are replaced to be de-recognized.

IFRS specifically requires de-recognition of the replaced parts regardless of whether the replaced parts had been depreciated separately.

Impact on the Corporation

On transition, the carrying amount of replaced parts totaling $7.3 million were de-recognized. The tax impact of this adjustment was $1.8 million, resulting in a net decrease in retained earnings of $5.5 million.

As a result of this change, depreciation expense was lower by $0.1 million (rounding) for the three-month period ended June 30, 2014, and $0.1 million (rounding) for the six-month period ended June 30, 2014.

(iii) PPE (pre-operating costs)

Canadian GAAP allows incidental revenues and costs to be included in the costs of the assets being built.

IFRS requires the income and related expenses of incidental operations, which are not necessary to bring an item to the location and condition necessary for it to be capable of operating in the manner intended by management, to be recognized in profit or loss.

Impact on the Corporation

On transition, net incidental revenues previously capitalized to a project were credited to retained earnings resulting in net increase in PPE of $1.7 million. The tax impact of this adjustment was $0.4 million resulting in a net increase in retained earnings of $1.3 million.

As a result of this change, depreciation expense was higher by $0.0 million (rounding) for the three-month period ended June 30, 2014, and $0.0 million (rounding) for the six-month period ended June 30, 2014.

(b) Post-retirement benefits

Under Canadian GAAP, the corridor approach allows the deferral of actuarial re-measurement gains and losses to be amortized over the expected average remaining service period of active employees.

IFRS does not allow the corridor approach and all actuarial re-measurement gains and losses are immediately recognized to other comprehensive income. Under IFRS, components of DB costs include service cost (other expense), net interest on the net benefit liability (finance charges) and re-measurements of the net benefit liability (other comprehensive income).

Impact on the Corporation

On transition, $66.0 million of unamortized actuarial losses were charged to retained earnings, the employee future benefits assets was reduced to nil, and post-employment benefits liabilities of $43.2 million was recorded. Since the Corporation's pension plan is held in a tax-exempt entity there was no tax effect on this adjustment.

As a result of this change, service cost decreased by $0.4 million for the three-month period ended June 30, 2014 and $0.9 million for the six-month period ended June 30, 2014. Also, net interest of $0.4 million for the three-month period ended June 30, 2014 and $0.8 million for the six-month period ended June 30, 2014 has been re-classed from other expense to finance charges.

(c) Business combination

Under Canadian GAAP, business combinations entered into prior to January 1, 2014 were measured at their fair value at the date of acquisition with any excess of the purchase price over the fair value of the net assets acquired recognized as goodwill. Any deficiency of the purchase price below the fair value of the net assets acquired was recorded as negative goodwill in the period of acquisition as a reduction to PPE.

Under IFRS, any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill while any deficiency of the purchase price below the fair value of the net assets acquired is recorded as a gain in the period of acquisition.

Impact on the Corporation

On transition date, PPE increased by $170.5 million and accumulated depreciation of $28.9 million were recognized in the carrying value of PPE. The adjustment resulted in a tax impact of $36.3 million and retained earnings increased by $105.3 million on transition date.

Subsequent to the negative goodwill reversal, an impairment charge was determined on the assets (see Note d). As a result of this change, depreciation expense was higher by $1.4 million for the three-month period ended June 30, 2014, and by $2.9 million for the six-month period ended June 30, 2014.

(d) Impairment testing

Under Canadian GAAP, the impairment test for PPE generally involves two steps. Under step one, the asset's carrying value is compared with undiscounted future cash flows to determine if an impairment exists. If an impairment exists, step two requires the impairment amount to be determined by comparing the asset's carrying value with the discounted future cash flows. Impairment charges could not be reversed under Canadian GAAP.

Under IFRS, the impairment test is a one-step process in which the carrying value of a CGU is compared to its recoverable amount. The recoverable amount is the greater of (1) fair value less cost of disposal and (2) value in use. Value in use is calculated by discounting future cash flows. Impairment charges related to PPE may be reversed if circumstances change. Impairments related to goodwill cannot be reversed.

Impact on the Corporation

On transition, the Corporation tested certain PPE with impairment indicators and goodwill for impairment. For the purpose of impairment testing, goodwill was allocated to the Kettles Hill Wind Farm CGU, which represents the lowest level within the Corporation at which the goodwill is monitored for internal management purposes.

The recoverable amount for the Corporation's CGUs was determined based on a value in use calculation, with the exception of the District Energy and Bonnybrook Energy Centre CGUs, which were determined based on a fair value less costs of disposal calculation. Value in use was calculated by discounting future cash flow projections based on the Corporation's internal budget. In arriving at its forecasts, management considered past experience, economic trends such as inflation, and industry and market trends. In determining fair value less costs of disposal, recent market transactions were taken into account; if these were not available, then a valuation model was used.

The discount rates used in the calculation of value in use and fair value less cost of disposal reflect current market assessments of the time value of money, and the risks specific to the asset for which future cash flow estimates have not been adjusted.

PPE and intangibles were impaired by $183.5 million, power purchase arrangement (PPA) were impaired by $3.4 million and goodwill was impaired by $16.0 million as of January 1, 2014. The reduction to PPE, PPA, and goodwill has a tax impact of $26.6 million and net opening retained earnings decreased by $176.3 million. As required by IFRS, the impairment was charged first to reduce any goodwill and then pro-rata to remaining assets of that CGU. The following table illustrates the impairment to goodwill and PPE by CGU as of January 1, 2014. The after-tax discount rates used to calculate value in use were in the range of 6.62 percent to 8.72 percent.

Cash generating unit *(millions of dollars)*	Impairment to goodwill	Impairment to PPE or PPA	Total impairment
Kettles Hill	16.0	7.1	23.1
Battle River	-	3.4	3.4
Calgary Energy Centre	-	95.8	95.8
District Energy	-	27.8	27.8
Bonnybrook	-	52.8	52.8
Total	16.0	186.9	202.9

As a result of this change, depreciation and amortization expenses were lower by $1.4 million for the three-month period ended June 30, 2014, and $2.8 million for the six-month period ended June 30, 2014.

(e) PPA amortization

Under Canadian GAAP, PPAs are amortized on a straight line basis over the contract term. Under IFRS, PPAs can be amortized over a shorter term based on the expected use of the assets.

Impact on the Corporation

On transition, accumulated amortization increased by $91.0 million with a tax impact of $22.7 million. The net decrease to retained earnings was $68.3 million. As a result of this change, amortization expense was lower by $3.2 million for the three-month period ended June 30, 2014, and $6.4 million for the six-month period ended June 30, 2014.

(f) Website

Under Canadian GAAP, if upgrades and enhancements of a website meet the definition of betterment (i.e., enhance the service potential of an intangible asset), those costs could be capitalized.

Under IFRS, only website development costs that can be demonstrated to generate probable future economic benefits (generating revenues) can be recognized as intangibles. A website that is developed solely to promote or advertise an entity's products or services would not meet the condition for recognition.

Impact on the Corporation

On transition, $9.1 million of website development costs included in intangibles were charged to retained earnings with no tax impact, as the intangibles are held in a tax-exempt entity.

As a result of this change, amortization expense was lower by $0.2 million for the three-month period ended June 30, 2014 and $0.5 million for the six-month period ended June 30, 2014.

(g) Provisions

(i) Provisions (asset retirement obligations)

Under Canadian GAAP, asset retirement obligations (ARO) are calculated by estimating the future cash outflows and discounting them using a credit-adjusted, risk-free rate. Changes in the net present value of the future retirement obligation were included as accretion expense.

Under IFRS, AROs are calculated using risk-adjusted future cash flows discounted using the risk-free rate at each reporting period. Changes in the net present value of the future retirement obligations are included in finance charges.

Impact on the Corporation

On transition, ARO assets of $20.0 million have been recognized in the carrying value of PPE. The ARO liability increased by $34.5 million. The tax impact of this adjustment is $3.6 million resulting in a net decrease of $10.9 million to opening retained earnings on transition.

During 2014, ARO assets and ARO liabilities increased by $2.9 million as a result of re-measuring the ARO related to the acquisitions of Cavalier Power Station and Balzac Power Station in Q3 under IFRS.

The unwinding of the discount is now included in finance charges. Accretion expense in the amount of $0.3 million has been re-classed from other expense to finance charges for the three-month period ended June 30, 2014 and $0.3 million for the six-month period ended June 30, 2014. In addition, depreciation expense was $0.1 million higher and finance charges were $0.1 million higher for the three-month period ended June 30, 2014. Depreciation expense was $0.3 million higher and finance charges were $0.4 million higher for the six-month period ended June 30, 2014.

(ii) Provisions (constructive obligation)

Under Canadian GAAP, constructive obligations are recognized only if required by a specific standard.

Under IFRS, a provision is recognized as constructive obligation if there is a probable outflow of resources and the amount can be estimated reliably.

Impact on the Corporation

On transition, the Corporation recognized constructive obligation related to the expected cost of profit-sharing and bonus payments. Bonus liability increased by $8.7 million with no deferred tax impact.

As a result of this change, bonus expense was higher by $0.6 million in the three-month period ended June 30, 2014, and $1.1 million for six-month period ended June 30, 2014.

(iii) Provisions (onerous contracts obligation)

Under Canadian GAAP, a provision for an onerous contract is recognized only when required by a specific standard. Under IFRS, a provision is recognized for an onerous contract when the costs of meeting the obligations under the contract exceed the benefits to be derived.

Impact on the Corporation

On transition, the Corporation recognized $20.0 million of onerous liability for certain contracts related to an impaired CGU with no deferred tax impact.

As a result of this change, operating expenses were lower by $0.2 million for the three-month period ended June 30, 2014, and $0.5 million for the six-month period ended June 30, 2014.

(h) Financial instruments

Canadian GAAP requires an entity to document its basis for concluding that a contract is for the receipt or delivery of a non-financial item in accordance with its expected purchase, sale and usage requirements.

Under IFRS, the documentation requirement does not exist.

Impact on the Corporation

On transition, the Corporation was able to reverse one of its contracts that was treated as mark-to-market through OCI. This contract is for the physical delivery of electricity to a retail customer and meets the requirements of "own use" under IFRS. The adjustment on transition is a decrease to long-term financial assets of $1.5 million. In addition, a $0.4 million increase of deferred income tax asset and a decrease of $1.1 million of AOCI is recognized on transition.

As a result of this change, OCI was higher by $0.0 million (rounding) for the three-month period ended June 30, 2014, and lower by $0.0 million (rounding) for the six-month period ended June 30, 2014.

EXPLANATION OF THE RECLASSIFICATION ADJUSTMENTS IN THE TABLES ABOVE

1. Reclassification adjustment (1) reclassifies the current portion of deferred income tax asset (liability) from current to long term in accordance with IAS 1, "Presentation of Financial Statements."
2. IAS 1 requires the statement of financial position to include separate line items for financial assets that are included in other current assets and other assets under Canadian GAAP.
3. IAS 1 requires the statement of financial position to include separate line items for financial liabilities that are included in other current liabilities and other liabilities under Canadian GAAP.
4. IFRS 14 requires separate disclosure in the statement of financial position for (a) the total of all regulatory deferral account debit balances and (b) the total of all regulatory deferral account credit balances.
5. IFRIC 18 requires contributions from customers for PPE be classified as deferred revenues, versus netted against PPE under previous GAAP.

Adjustments to the statement of cash flows

The transition from Canadian GAAP to IFRS had no significant impact on cash flows generated by the Corporation.

21. SUBSEQUENT EVENTS

On July 20, 2015, the terms of the credit facilities were extended by one year. The letter of credit tranches in the amount of $300.0 million expiry July 20, 2018 and the operating tranches in the amount of $550.0 million expiry July 20, 2020.

ADDITIONAL INFORMATION

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

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