ENMAX CORPORATION

Q2 2018 INTERIM REPORT

CAUTION TO READER

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

When used in this 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

This MD&A, dated August 22, 2018, is a review of the results of operations of ENMAX and its subsidiaries ('the Corporation') for the three and six month period ended June 30, 2018, compared with 2017, and of the Corporation's financial condition and future prospects. This MD&A should be read in conjunction with the Q2 2018 Condensed Consolidated Interim Financial Statements and the 2017 ENMAX Financial Report, which is available on ENMAX's website at www.enmax.com, as information has been omitted from this MD&A if it remains substantially unchanged.

ENMAX's Condensed Consolidated Interim Financial Statements have been prepared in accordance with International Financial Reporting Standards (IFRS). The Condensed Consolidated Interim Financial Statements and MD&A were reviewed by ENMAX's Audit Committee, and were approved by ENMAX's Board of Directors. All amounts are in millions of Canadian dollars unless otherwise specified.

The Corporation reports on certain non-IFRS financial performance measures that are used by management to evaluate performance of the Corporation and its business segments. Because non-IFRS financial measures do not have a standard meaning prescribed by IFRS, the Corporation has defined and reconciled them with their nearest IFRS measure. For the reader's reference, the definition, calculation and reconciliation of non-IFRS financial measures is provided in the Non-IFRS Financial Measures section.

Contents

Glossary of terms can be found on page 40 of the Condensed Consolidated Interim Financial Statements

MARKET CONDITIONS

The second quarter of 2018 saw a noticeable increase in price and price volatility. The average spot electricity price in Alberta for the three months ended June 30, 2018 increased 190 per cent over the same period last year to $56/Megawatt hour (MWh). May and June 2018 experienced the highest monthly average prices since February 2014. At the heart of these increases were weather, an increase in the carbon levy on coal-fired generation, coal retirements and deactivation/mothballing, and changes in offer behavior related to Power Purchase Arrangement (PPA) assets being returned to operators.

Prices are expected to remain elevated in the near term as a result of announced coal retirements and the anticipated return of the Battle River 5 PPA to its owner by September 30, 2018. Changing market conditions are favouring highly efficient gas-fired generators who benefit from historically low gas prices and reductions in their compliance costs under Carbon Competitiveness Incentive Regulation (CCIR). ENMAX's portfolio of natural gas-fired power plants and wind farms positions us well to capitalize on the increased prices; however, the hedging program which sheltered us during the downturn of 2016-2017 is expected to limit some of the potential upside provided by these conditions.

Alberta demand (load) averaged 9,181 MW in Q2, representing an increase of four per cent over the same quarter in 2017 and is continuing along a reasonable growth trajectory. ENMAX's unique vertically integrated business model, which includes making, moving and marketing electricity, will allow it to benefit from this growth through generation revenue growth, retail site growth, and transmission and distribution growth.

Natural gas prices averaged $1.14/Gigajoule (GJ) in Q2 2018, down from $1.96/GJ in Q1 2018, and from $2.64/GJ in Q2 2017. Weak gas prices over the quarter were attributed to continued maintenance work on gas pipelines that move the gas to storage or to other markets creating over-supplied conditions in our market. The downward pressure on natural gas prices is generally positive for ENMAX's portfolio of natural gas-fired power plants; however, the continued pipeline restrictions pose gas delivery risk to ENMAX assets, creating financial and operational challenges.

From an overall market structure perspective, the Alberta Electric System Operator (AESO) released the final version of the Comprehensive Market Design (CMD) for the capacity market in June, 2018. Certain elements of the capacity market remain outstanding and subject to additional stakeholder consultation and regulatory proceedings. The first capacity market auction is targeted to occur in Q2 2020 with the first delivery period scheduled to begin in Q4 2021. ENMAX is continuing to evaluate the impact of the capacity market on its business and customers.

FINANCIAL PERFORMANCE

Management believes that a measure of operating performance is more meaningful if results not related to normal operations are excluded from the adjusted financial information. As a result the table below presents ENMAX's Adjusted EBITDA, Adjusted EBIT and comparable net earnings. These financial metrics exclude impairment, onerous provision charges on long-term contracts, foreign exchange gains (losses) and unrealized gains (losses) on commodities where settlement on derivatives will occur in a future period. Refer to the Non-IFRS Financial Measures section for definition of the financial measures and further description, on page 10.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

	Three months ended June 30,		Six months ended June 30,	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**
Total revenue	584.7	447.8	1,155.0	977.0
Adjusted EBITDA [(1)(2)]				
Competitive Energy	31.8	38.6	85.7	103.9
Power Delivery	52.7	46.5	102.1	91.3
Corporate and Eliminations	0.8	1.3	0.2	4.4
Consolidated	85.3	86.4	188.0	199.6
Adjusted EBIT [(1)(2)]				
Competitive Energy	4.1	9.8	30.0	46.3
Power Delivery	27.2	23.1	50.9	44.9
Corporate and Eliminations	(2.4)	(1.3)	(6.3)	(1.0)
Consolidated	28.9	31.6	74.6	90.2
Comparable net earnings [(1)(2)(3)]	21.6	20.0	53.1	62.9
Net earnings (loss)	34.9	(0.9)	(88.2)	(3.4)
Free cash flow	20.8	39.0	58.5	(38.9)
Capital expenditures	85.6	78.9	165.3	168.1

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

[(2)] Does not include

- Realized and unrealized foreign exchange of $5.4 million gains and $11.7 million gains (2017 - $5.8 million loss and $5.4 million loss), for the three and six months ended June 30, 2018 respectively.
- Unrealized electricity and gas mark-to-market for the three and six months ended June 30, 2018 of $13.0 million and $2.8 million gains respectively, (2017 - $22.9 million and $85.5 million losses).
- Recovery of onerous provision $nil and $12.5 million gain (2017 - $nil and $nil) for the three and six months ended June 30, 2018, respectively.

[(3)] Does not include a one-time tax expense of $164.3 million booked in Q1 2018 (2017 - $nil).

Total revenue for the three and six months ended June 30, 2018 has increased by $136.9 million and $178 million, respectively, from the comparable periods in 2017. This strong growth is related to the changes in the Alberta electricity market (see Market Conditions section) that have increased the price we receive on our generated electricity, although given our hedging program it only reflects a portion of the market increase. ENMAX has also seen strong revenue growth in its Power Delivery segment related to its regulated distribution revenues.

ENMAX's Consolidated Adjusted EBIT decreased by $2.7 million for the three months ended and $15.6 million for the six months ended June 30, 2018, as compared with the prior year. The primary drivers for the change in Adjusted EBIT were as follows:

- ENMAX Competitive Energy (Competitive Energy) - The power services business was impacted by severe and prolonged winter weather conditions, which delayed the completion of projects in the first quarter of 2018, and negatively affected the segment's overall YTD 2018 adjusted EBIT performance. Competitive Energy's margin was further impacted by changes in retail customer product preferences. The increase in market power prices experienced in 2018 have had a limited impact on our achieved electricity margins due to Competitive Energy's strategy of hedging a significant portion of our commodity margin. With respect to natural gas products, Competitive Energy was able to realize higher margins, partially offsetting the decrease in electricity and contractual services margins from the prior period.

- ENMAX Power Delivery (Power Delivery) - The regulated business continues to grow through investment and the increase in customer sites. This is largely a result of the Calgary service area's continued growth and the need to replace its aging infrastructure. Power Delivery is actively working to minimize regulatory earnings lag. The increase in regulatory margins in the first half of 2018 reflects changes due to the AUC approved 2017 Transmission Compliance Filing.
- ENMAX Corporate and Eliminations (Corporate) - With the completion of ENMAX's new integrated systems on January 3, 2018, the higher system investment costs incurred throughout 2017 have begun to return to sustainment levels. Management expects to see this favourable year-over-year variance grow through the remainder of 2018. This favourable trend has been offset by a decrease in intercompany interest charges in 2018, which are eliminated upon consolidation.

ENMAX's net earnings increased by $35.8 million for the three months ended and decreased $84.8 million for the six months ended June 30, 2018 as compared with the prior year. The stronger results during the three month period ended June 30, 2018 compared to the prior year mainly related to an increase of $35.9 million on unrealized gains on commodities that settle in future periods. The main driver for the six month decrease is the $164.3 million of tax expense booked during the first quarter of 2018 as a result of the Alberta Court of Appeal decision related to intercompany loan interest over the period 2004 to 2017 (see Income Tax section for further details).

As at June 30, 2018, ENMAX's balance sheet continued to show strength as the Company carefully manages debt to cash flow ratios as well as capital investment. ENMAX's cash flow has enabled the Corporation to continue to achieve growth and profitability in the uncertain economic environment.

Additional details on the financial performance of the Corporation are discussed in the ENMAX Financial Results section.

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

SIGNIFICANT EVENTS

PPA TERMINATIONS

On March 9, 2018, the Government of Alberta dismissed the Alberta Application against all parties, including ENMAX. In connection with this, ENMAX agreed to transfer 166,667 carbon offset credits to the Balancing Pool during 2018 and the Balancing Pool paid ENMAX $5.0 million in relation to previously disputed and unpaid dispatch services and PPA transition matters. No provisions were recognized with respect to the Alberta Application as the Corporation always believed that the terminations were exercised in accordance with the provisions of the PPAs.

TAX LITIGATION UPDATE

On April 26, 2018, the Alberta Court of Appeal issued its decision relating to interest expense deductions by ENMAX Energy Corporation and ENMAX PSA Corporation, ENMAX has filed an application with the Supreme Court of Canada seeking leave to appeal, see the Income Tax section of this document.

ENMAX COMPETITIVE ENERGY BUSINESS UPDATE

Competitive Energy is an integrated business providing customers with electricity, natural gas, energy solutions and power project services through ENMAX Power Services Corp (EPSC). Our competitive advantage is our retail business which acts as a hedge of our wind and gas-fueled generation assets and provides opportunities to offer additional energy solutions such as solar installations for our customers. As at June 30, 2018, Competitive Energy's capacity ownership interest was 1,617 MW of electricity generation, 1,397 MW from natural gas-fueled plants, 217 MW from wind power and 3 MW from a combined heat and power unit (CHP). Electricity contracts link customer demand to generating assets resulting in relatively predictable margins. If Competitive Energy requires power to meet its retail or wholesale customer needs, it is procured from the energy market. When Competitive Energy has excess generation capacity, it can sell the energy to the market.

Natural gas retail contracts are backed by market transactions to provide supply certainty along with margin stability and risk mitigation. Natural gas fuel requirements for the portfolio are balanced through the purchase and sale of natural gas from and in to the Alberta market.

KEY BUSINESS STATISTICS

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	2018	2017
Plant availability (%) [1]	78.04	97.49	87.89	97.94
Average pool price ($/MWh)	55.92	19.26	45.36	20.82
Average spark spread ($) [2]	47.36	(0.52)	33.75	1.38

[1] Plant availability includes planned maintenance and forced outages.
[2] Based on market prices.

Plant availability was lower than the prior year due to planned outage events in 2018 at the Shepard Energy Centre and Calgary Energy Centre.

During 2018, the average flat pool power price increased from 2017 levels for the comparative period. This was primarily due to the increase in the carbon levy on coal generation, higher system load and the retirement and mothballing of coal assets.

Spark spread, which is the difference between the wholesale electricity price and the price of natural gas to produce the electricity, represents the gross margin contribution of a gas-fueled power plant from generating a unit of electricity. It improved from 2017 levels, driven by increased average flat pool prices of $55.92/MWh (2017 - $19.26/MWh) for the three months ended June 30, 2018 and $45.36/MWh (2017 - $20.82/MWh) for the six months ended June 30, 2018 combined with a decrease in the market prices related to natural gas.

ENMAX manages it portfolio to deliver on our cash flow targets by using a combination of retail sales and forward markets with hedges. This reduces volatility of cash flows with respect to the market prices.

ENMAX POWER DELIVERY BUSINESS UPDATE

ENMAX Power Delivery's highest priorities are providing safe, reliable and efficient delivery of electricity to its customers.

Power Delivery continues to invest in its electricity 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 can include capacity upgrades to existing substations, existing transmission lines, new substations, and new transmission lines to deliver reliable electricity to meet Calgary's growing demand.

Power Delivery submits applications to the Alberta Utilities Commission (AUC) to request approval of construction or replacement of utility-related facilities and to set rates for providing electric energy delivery-related services to its customers, among other things.

- On June 19, 2018, the AUC issued an early decision on ENMAX Power Corporation's (EPC) compliance filing to its 2016-2017 Transmission General Tariff Application. The Commission approved EPC's revised revenue requirement of $71.6 million for 2016, and $81.2 million for 2017. EPC successfully recovered the previously deferred capitalized overhead amounts of $3.6 million as operations and maintenance expense. This concludes the process which began in December 2016 when the application was first filed and the outcomes are reflected in the Q2 2018 Financial Report.
- In the Generic Performance Based Regulation (PBR) decision issued by the AUC on February 5, 2018, the AUC denied all proposed utility adjustments and reduced the incremental capital funding mechanism. This decision negatively impacts the revenue for ENMAX's distribution business for the next five years, starting January 1, 2018. ENMAX, ATCO and Fortis filed separate applications to review and vary the decision and applications for permission to appeal the decision to the Alberta Court of Appeal.
- On July 5, 2017, the AUC initiated the 2018 Generic Cost of Capital proceeding. A decision was rendered by the AUC on August 2, 2018, which applies to the years 2018 to 2020. For ENMAX Power Delivery, the final approved return on equity remained at 8.5% and the final approved deemed equity ratio is 37% (it was previously set at 36%). The results of this decision will be reflected in our Q3 2018 and other future financial statements.

Power Delivery continues its efforts to reduce the regulatory earnings lag, promote cost efficiencies and focus on prudent capital expenditures.

KEY BUSINESS STATISTICS

	Three months ended June 30,		Six months ended June 30,	
	2018	**2017**	**2018**	**2017**
Distribution volumes in gigawatt hours (GWh)	2,281	2,296	4,715	4,670
System average interruption duration index (SAIDI) [1]	0.17	0.13	0.27	0.19
System average interruption frequency index (SAIFI) [2]	0.34	0.23	0.46	0.29

[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. The lower the SAIDI, the better the reliability.

[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. The lower the SAIFI, the better the reliability.

Total electricity delivered in GWh to the Calgary service area for the 2018 period was slightly higher than the prior year. An increase in the number of customer sites contributed to increased distribution volume in 2018.

When compared to other Canadian Electricity Association member utilities, ENMAX has consistently been one of the most reliable transmission and distribution utilities in Canada. The SAIDI and SAIFI are unfavourable compared to the same periods in 2017 due to increased cable faults, pole fires and scheduled outages. The scheduled outages are performed for equipment repairs and capital projects from infrastructure builds.

ENMAX FINANCIAL RESULTS

ADJUSTED EARNINGS BEFORE INTEREST AND INCOME TAXES (ADJUSTED EBIT) COMPARED WITH THE SAME PERIOD IN 2017

For the three months ended June 30, *(millions of dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate**	**Consolidated**
Adjusted EBIT[1] for the three months ended June 30, 2017	9.8	23.1	(1.3)	31.6
Increased (decreased) margins attributable to:				
Electricity	(7.6)	0.1	-	(7.5)
Natural gas	0.6	-	(0.2)	0.4
Transmission and distribution	-	5.8	-	5.8
Contractual services and other	5.2	1.5	(1.7)	5.0
Decreased (increased) expenses:				
Operations, maintenance & administration [2]	(5.0)	(1.2)	1.4	(4.8)
Amortization	1.1	(2.1)	(0.6)	(1.6)
Adjusted EBIT[1] for the three months ended June 30, 2018	**4.1**	**27.2**	**(2.4)**	**28.9**

[1] Adjusted EBIT is a non-IFRS measure. See Non-IFRS Financial Measures section.
[2] Normalized to exclude impact of intercompany transactions with no consolidated impact.

For the six months ended June 30, *(millions of dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate**	**Consolidated**
Adjusted EBIT[1] for the six months ended June 30, 2017	46.3	44.9	(1.0)	90.2
Increased (decreased) margins attributable to:				
Electricity	(11.9)	(0.4)	(1.5)	(13.8)
Natural gas	2.7	-	(0.2)	2.5
Transmission and distribution	-	9.8	-	9.8
Contractual services and other	(3.8)	2.6	(4.2)	(5.4)
Decreased (increased) expenses:				
Operations, maintenance & administration [2]	(5.2)	(1.2)	1.7	(4.7)
Amortization	1.9	(4.8)	(1.1)	(4.0)
Adjusted EBIT[1] for the six months ended June 30, 2018	**30.0**	**50.9**	**(6.3)**	**74.6**

[1] Adjusted EBIT is a non-IFRS measure. See Non-IFRS Financial Measures section.
[2] Normalized to exclude impact of intercompany transactions with no consolidated impact.

Electricity margins for the three and six months ended June 30, 2018 decreased $7.5 million or 9.9 per cent, and $13.8 million or 8.3 per cent, respectively, compared to the prior year largely resulting from a continued shift in retail customer product preferences. The recent increase in market power prices have had a limited impact on electricity margins in 2018, as our normal practice is to contract a majority of our market position to stabilize margins and mitigate risk. Spark spread changes only impact the uncontracted position, which varies as we move along our risk mitigation strategy into future periods.

During the three and six months ended June 30, 2018, natural gas margins increased $0.4 million or 3.8 per cent, and $2.5 million or 8.7 per cent, respectively, compared to the prior year. The increase was primarily due to higher retail consumption volumes as a result of increased site acquisitions and colder temperatures experienced in the first three months of 2018 compared to 2017.

For the three and six months ended June 30, 2018, transmission and distribution margins increased $5.8 million or 8.2 per cent and $9.8 million or 6.9 per cent, respectively, compared to the same period in 2017. The favourable variance was largely due to the changes to the AUC approved 2017 Transmission compliance filing.

Contractual services and other margins increased $5.0 million or 27.2 per cent for the three months ended June 30, 2018 and decreased $5.4 million or 11.4 per cent for the six months ended June 30, 2018 when compared to the same period in 2017. The favourable variance in the quarter is due to better weather conditions allowing ENMAX's crews to catch up on the project backlog created in Q1 by the poor weather. For the six months ended June 30, 2018, the unfavourable variance is primarily due to higher emissions offset sales and use in 2017 that have not been duplicated at the same level or timing in 2018.

During the three and six months ended June 30, 2018, operations, maintenance & administration (OM&A) expenses increased by $4.8 million or 5.3 per cent and $4.7 million or 2.6 per cent, respectively, compared to the same periods in 2017. These unfavourable variances are the result of year over year staffing cost increases across the business, and outage related repair and maintenance costs at two of ENMAX's facilities during planned outages in the quarter that did not occur in the prior year.

Amortization expense increased $1.6 million or 2.9 per cent and $4.0 million or 3.7 per cent when compared to the same three and six month periods in 2017. The increase in expense was consistent with an increase in capital assets in service.

OTHER NET EARNINGS ITEMS

The calculation of the Corporation's current and deferred income taxes involves a degree of estimation and judgment. The carrying value of deferred income tax assets is reviewed at the end of each reporting period. For the six months ended June 30, 2018, management adjusted the income tax provision utilizing its best estimate with considerations including management's expectation of future operating results, interpretation of applicable tax regulations positions, allowances where uncertainty surrounding the realization of the tax benefit exists, and the settlement of the various tax disputes.

For the three and six months ended June 30, 2018, tax recovery of $5.4 million and tax expense of $154.6 million (2017 - recoveries of $14.0 million and $32.9 million), respectively, the change in the income tax expense is primarily due to the impact of the Alberta Court of Appeal decision.

OTHER COMPREHENSIVE INCOME AND SHAREHOLDER'S EQUITY

Other comprehensive income (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 as well as re-measurement gains and losses on pension retirement benefits.

For the three and six months ended June 30, 2018, OCI had losses of $0.2 million and gains of $27.7 million respectively, compared with gains of $58.7 million and $38.7 million, respectively, for the same periods in 2017. The OCI changes primarily reflect the fair value changes in electricity and commodity positions.

Accumulated other comprehensive income (loss) is reflected in shareholder's equity along with retained earnings and share capital. Retained earnings for the period declined $129.6 million largely from the net loss in the period related to the tax trial decision of the Alberta Court of Appeal in Q1 2018.

NON-IFRS FINANCIAL MEASURES

The Corporation uses adjusted earnings before interest, taxes, depreciation and amortization (Adjusted EBITDA), adjusted earnings before interest and taxes (Adjusted EBIT), comparable net earnings, and free cash flow (FCF) as financial performance measures. 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.

ADJUSTED EARNINGS BEFORE INTEREST, TAXES, DEPRECIATION AND AMORTIZATION (ADJUSTED EBITDA)

	Three months ended June 30,		Six months ended June 30,	
(millions of dollars)	**2018**	**2017**	**2018**	**2017**
Adjusted EBITDA (non-IFRS financial measure)	**85.3**	86.4	**188.0**	199.6
Depreciation and amortization	56.4	54.8	113.4	109.4
Finance charges	17.9	17.8	35.2	35.7
Income tax recovery	(10.5)	(6.2)	(13.6)	(8.4)
Comparable net earnings (non-IFRS financial measure)	**21.5**	20.0	**53.0**	62.9
Unrealized (gains) losses on commodities	(13.0)	22.9	(2.8)	85.5
Foreign exchange (gains) losses	(5.4)	5.8	(11.7)	5.4
Recovery of onerous provision	-	-	(12.5)	-
Net income tax expense (recovery) on unrealized (gains) loss on commodities and foreign exchange (gains) losses	5.0	(7.8)	3.9	(24.6)
One time tax adjustment	-	-	164.3	-
Net earnings (loss) (IFRS financial measure)	**34.9**	(0.9)	**(88.2)**	(3.4)

Adjusted EBITDA is considered a useful measure of business performance as it provides an indication of the cash flow results generated by primary business activities without consideration as to how those activities are financed and amortized, or how the results are taxed. Adjusted EBITDA is also used to evaluate certain debt coverage ratios.

Adjusted EBITDA is normalized for realized and unrealized foreign exchange (gains) losses, unrealized (gains) losses on commodities and recovery of onerous provision. Management believes that a measure of operating performance is more meaningful if results not related to normal operations are excluded from the adjusted operating profit. Unrealized (gains) losses on commodities reflect the impact of changes in forward natural gas and power prices and the volume of the positions for these derivatives over a certain period of time. These unrealized (gains) losses do not necessarily reflect the actual gains and losses that will be realized on settlement. Furthermore, unlike commodity derivatives, ENMAX's generation capacity and future sales to retail customers are not marked to market under IFRS.

ADJUSTED EBIT

(millions of dollars)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Operating profit (loss) (IFRS financial measure)	**34.5**	(14.2)	**85.0**	(37.3)
Add:				
Adjustments for rate-regulated activities	12.8	17.1	16.6	36.6
Unrealized (gains) losses on commodities	(13.0)	22.9	(2.8)	85.5
Foreign exchange (gains) losses	(5.4)	5.8	(11.7)	5.4
Recovery of onerous provision	-	-	(12.5)	-
Adjusted EBIT (non-IFRS financial measure)	**28.9**	31.6	**74.6**	90.2
Deduct:				
Unrealized (gains) losses on commodities	(13.0)	22.9	(2.8)	85.5
Foreign exchange (gains) losses	(5.4)	5.8	(11.7)	5.4
Finance charges	17.9	17.8	35.2	35.7
Recovery of onerous provision	-	-	(12.5)	-
Income tax (recovery) expense	(5.5)	(14.0)	154.6	(33.0)
Net earnings (loss) (IFRS financial measure)	**34.9**	(0.9)	**(88.2)**	(3.4)

The Corporation focuses on Adjusted EBIT, which excludes the impact of foreign exchange (gains) losses, unrealized (gains) losses on commodities and recovery of onerous provision. Adjusted EBIT is a useful measure of business performance, which provides an indication of the operating results generated by primary business activities.

Management believes that the normalization of this non-IFRS measure provides a better representation of the underlying operations of the Corporation.

FREE CASH FLOW (FCF)

ENMAX defines free cash flow as IFRS net cash provided by operating activities less capital expenditures. Management believes that FCF is a liquidity measure that provides useful information regarding cash provided by operating activities and cash used for investments in property and equipment required to maintain and grow the business.

(millions of dollars)	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
Net cash provided by operating activities	106.4	117.9	223.8	129.2
Capital expenditures	(85.6)	(78.9)	(165.3)	(168.1)
Free cash flow	**20.8**	39.0	**58.5**	(38.9)

FINANCIAL CONDITION

SIGNIFICANT CHANGES IN THE CORPORATION'S FINANCIAL CONDITION

As at *(millions of dollars, except % change)*	June 30, 2018	December 31, 2017	$ Change	% Change	Explanation for Change
ASSETS					
Cash and cash equivalents	54.0	81.2	(27.2)	(33%)	Primarily due to cash used for purchase of property, plant and equipment, and the repayment of short-term debt.
Accounts receivable	613.4	629.5	(16.1)	(3%)	Seasonally lower gas consumption in the second quarter due to warmer temperatures.
Property, plant and equipment	4,181.8	4,148.7	33.1	1%	Capital additions largely offset by amortization.
LIABILITIES AND SHAREHOLDER'S EQUITY					
Accounts payable	419.0	367.7	51.3	14%	Timing of payroll related accruals and higher business activity such as planned outages
Financial liabilities [(1)]	92.4	134.8	(42.4)	(31%)	Change in fair value of hedged and non-hedged derivatives.
Long-term debt [(1)]	1,723.1	1,580.8	142.3	9%	Additional $177.4 million of ACFA debt acquired during Q2.

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

LIQUIDITY

ENMAX actively monitors its cash position and anticipated cash flows to optimize funding levels. The Corporation also communicates its capital position regularly with credit rating agencies and the investment community. ENMAX finances working capital requirements, capital investments and any maturities of long-term debt through a combination of cash flow from operations, commercial paper and new long-term debt.

ENMAX has maintained an investment grade credit rating since the Corporation's inception. By maintaining this strong credit rating, ENMAX is able to minimize the Corporation's financing costs and allow efficient and cost effective access to funds used in operations and growth. During the quarter, both Standard & Poor's and Dominion Bond Rating Service Limited reiterated their investment grade credit ratings for the Corporation of BBB and A (low), respectively. Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at June 30, 2018, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

ENMAX's total debt balance at June 30, 2018 was $1,723.1 million (December 31, 2017 - $1,788.5 million) of which $nil (December 31, 2017 - $207.7 million) is in commercial paper. On June 19, 2018, ENMAX refinanced the maturing $300.0 million private debentures with an interest rate of 6.15 per cent with a new $300.0 million private debenture with an interest rate of 3.84 per cent and a 10 year term. During the quarter ended June 30, 2018, ENMAX also acquired $177.4 million of debentures from The City of Calgary through arrangements with the Alberta Capital Finance Authority (ACFA) with an average rate of 3.11 per cent with maturities ranging from 2023 to 2043.

Currently, ENMAX has access to $850.0 million (December 31, 2017 - $850.0 million) in credit facilities, of which $356.9 million (December 31, 2017 - $262.3 million) has been drawn upon. These credit facilities mature between 2020 and 2021 and are provided by international, national and regional lenders.

When prudent, ENMAX invests temporary surplus cash balances in short-term interest-bearing instruments to maximize investment income to fund future operating and maintenance costs.

INCOME TAX

When Alberta Finance, Tax and Revenue Administration conducted its 2006 audit of ENMAX Energy Corporation and ENMAX PSA Corporation, it disagreed with the rate of interest on intercompany loans. The interest expense was deducted on income tax returns filed under the Payment in Lieu of Tax Regulation of the Electric Utilities Act (Alberta) for the 2004 to 2017 fiscal years. None of the loans remain outstanding.

On June 17, 2016, the Court of Queen's Bench of Alberta issued its decision in favour of ENMAX. Alberta Finance appealed this decision to the Alberta Court of Appeal. On April 26, 2018, the Alberta Court of Appeal issued its decision allowing the Crown's appeal and reinstating the Notices of Reassessment previously issued by Alberta Finance. On June 21, 2018, ENMAX filed an application seeking leave to appeal to the Supreme Court of Canada. A decision on the leave application is expected during 2018.

The Notices of Reassessment reflect a lower interest rate than provided for under the intercompany loans. As a result, we have recognized tax expenses of $164.3 million, which reflects our current estimate of the difference in the applicable interest rates as well as interest over the 14 year period. ENMAX expects that there will be adjustments to this amount in future periods as the assumptions applied are refined and confirmed.

RISKS AND RISK MANAGEMENT

There have been no material changes in the three months or six months ended June 30, 2018 to the Corporation's business and operational risks as described in the Corporation's December 31, 2017 MD&A.

CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

(unaudited) *(millions of Canadian dollars)*	**June 30, 2018**	**December 31, 2017**
ASSETS		
Cash and cash equivalents	**54.0**	81.2
Accounts receivable (Note 4)	**613.4**	629.5
Income taxes receivable	**0.7**	87.5
Current portion of financial assets (Note 7)	**103.8**	98.9
Other current assets (Note 9)	**124.6**	109.4
	896.5	1,006.5
Property, plant and equipment	**4,181.8**	4,148.7
Intangible assets	**179.7**	182.9
Deferred income tax assets (Note 10)	**38.6**	81.3
Financial assets (Note 7)	**56.2**	49.4
Other long-term assets (Note 9)	**24.5**	26.1
TOTAL ASSETS	**5,377.3**	5,494.9
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES (Note 8)	**92.6**	76.2
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	**5,469.9**	5,571.1
LIABILITIES		
Short-term financing (Note 7)	**-**	207.7
Accounts payable and accrued liabilities	**419.0**	367.7
Income taxes payable (Note 10)	**45.4**	1.8
Dividend payable (Note 13)	**20.0**	-
Current portion of long-term debt (Note 7)	**75.3**	367.3
Current portion of financial liabilities (Note 7)	**112.8**	141.8
Current portion of deferred revenue	**6.1**	4.7
Other current liabilities (Note 9)	**27.3**	27.4
Current portion of asset retirement obligations and other provisions	**2.5**	2.8
	708.4	1,121.2
Long-term debt (Note 7)	**1,647.8**	1,213.5
Deferred income tax liabilities (Note 10)	**62.9**	74.6
Post-employment benefits	**51.3**	50.4
Financial liabilities (Note 7)	**139.6**	141.3
Deferred revenue	**518.4**	510.3
Other long-term liabilities (Note 9)	**13.0**	15.9
Asset retirement obligations and other provisions	**107.2**	120.5
TOTAL LIABILITIES	**3,248.6**	3,247.7
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES (Note 8)	**9.2**	9.4
SHAREHOLDER'S EQUITY		
Share capital	**280.1**	280.1
Retained earnings	**1,892.6**	2,022.2
Accumulated other comprehensive income (Note 11)	**39.4**	11.7
TOTAL SHAREHOLDER'S EQUITY	**2,212.1**	2,314.0
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY	**5,469.9**	5,571.1

See accompanying Notes to Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF EARNINGS (LOSS)

(unaudited) *(millions of Canadian dollars)*	Three months ended June 30, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
REVENUE (Note 6)				
Electricity	**317.3**	211.8	**589.8**	453.2
Natural gas	**24.4**	32.6	**99.1**	113.4
Transmission and distribution	**160.0**	145.6	**320.1**	282.2
Local access fees	**34.2**	23.4	**63.6**	48.7
Contractual services	**41.2**	27.6	**65.1**	59.2
Contributions in aid of construction (CIAC) revenue	**4.5**	3.8	**8.7**	7.5
Other revenue (Note 12)	**3.1**	3.0	**8.6**	12.8
TOTAL REVENUE	**584.7**	447.8	**1,155.0**	977.0
OPERATING EXPENSES (Note 6)				
Electricity and fuel purchases	**236.1**	160.2	**435.1**	375.9
Natural gas and delivery	**13.6**	22.2	**68.0**	84.9
Transmission and distribution	**95.5**	89.9	**183.5**	172.7
Local access fees	**34.2**	23.4	**63.6**	48.7
Depreciation and amortization	**56.4**	54.8	**113.4**	109.4
Other expenses (Note 12)	**114.4**	111.5	**206.4**	222.7
TOTAL OPERATING EXPENSES	**550.2**	462.0	**1,070.0**	1,014.3
OPERATING PROFIT (LOSS)	**34.5**	(14.2)	**85.0**	(37.3)
Finance charges	**17.9**	17.8	**35.2**	35.7
NET EARNINGS (LOSS) BEFORE TAX	**16.6**	(32.0)	**49.8**	(73.0)
Current income tax expense (Note 10)	**0.2**	1.8	**133.6**	3.3
Deferred income tax expense (recovery) (Note 10)	**(5.7)**	(15.8)	**21.0**	(36.3)
NET EARNINGS (LOSS) BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS	**22.1**	(18.0)	**(104.8)**	(40.0)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNTS (Notes 6 and 8)	**12.8**	17.1	**16.6**	36.6
NET EARNINGS (LOSS)	**34.9**	(0.9)	**(88.2)**	(3.4)

See accompanying Notes to the Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited)	Three months ended June 30,		Six months ended June 30,	
(millions of Canadian dollars)	**2018**	**2017**	**2018**	**2017**
NET EARNINGS (LOSS)	**34.9**	(0.9)	**(88.2)**	(3.4)
Items that will not be reclassified subsequently to statement of earnings				
Remeasurement losses on retirement benefits (Note 16) [1]	**-**	-	**-**	0.2
Items that will be reclassified subsequently to statement of earnings				
Unrealized gains on derivative instruments[2]	**2.2**	45.3	**24.7**	13.2
Reclassification of gains (loss) on derivative instruments to net earnings[3]	**(2.4)**	13.4	**3.0**	25.3
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX	**(0.2)**	58.7	**27.7**	38.7
TOTAL COMPREHENSIVE INCOME (LOSS)	**34.7**	57.8	**(60.5)**	35.3

[1] Net deferred income tax expense of $nil for the three months ended June 30, 2018 (2017 - $nil), and $nil income tax expense for the six months ended June 30, 2018 (2017 - $0.2 million tax recovery).

[2] Net deferred income tax expense of $0.7 million for the three months ended June 30, 2018 (2017 - $16.7 million tax expense), and $9.1 income tax expense for the six months ended June 30, 2018 (2017 - $4.9 million tax expense).

[3] Net deferred income tax recovery of $1.2 million for three months ended June 30, 2018 (2017 - $4.6 million tax expense), and $0.2 income tax expense for the six months ended June 30, 2018 (2017 - $8.2 million tax expense).

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, 2018, as previously presented	280.1	2,022.2	11.7	2,314.0
Impact of the adoption of IFRS 9 (Note 4)	-	(1.4)	-	(1.4)
As at January 1, 2018, as restated	280.1	2,020.8	11.7	2,312.6
Net loss	-	(123.1)	-	(123.1)
Other comprehensive income, net of tax	-	-	27.9	27.9
Dividends (Note 13)	-	(40.0)	-	(40.0)
As at March 31, 2018	280.1	1,857.7	39.6	2,177.4
Net earnings	-	**34.9**	-	**34.9**
Other comprehensive (loss), net of tax	-	-	**(0.2)**	**(0.2)**
As at June 30, 2018	**280.1**	**1,892.6**	**39.4**	**2,212.1**
As at January 1, 2017	280.1	2,100.5	(89.3)	2,291.3
Net loss	-	(3.4)	-	(3.4)
Other comprehensive income, net of tax	-	-	38.7	38.7
Dividends (Note 13)	-	(48.0)	-	(48.0)
As at June 30, 2017	280.1	2,049.1	(50.6)	2,278.6
Net loss	-	(26.9)	-	(26.9)
Other comprehensive income, net of tax	-	-	62.3	62.3
As at December 31, 2017	**280.1**	**2,022.2**	**11.7**	**2,314.0**

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, 2018	Three months ended June 30, 2017	Six months ended June 30, 2018	Six months ended June 30, 2017
CASH PROVIDED BY (USED IN):				
OPERATING ACTIVITIES				
Net earnings (loss)	**34.9**	(0.9)	**(88.2)**	(3.4)
Items not involving cash:				
Contributions in aid of construction (CIAC)	**13.2**	25.3	**18.2**	37.1
CIAC revenue	**(4.5)**	(3.8)	**(8.7)**	(7.5)
Depreciation and amortization	**56.4**	54.8	**113.4**	109.4
Finance charges	**17.9**	17.8	**35.2**	35.7
Income tax expense (recovery) (Note 10)	**(5.5)**	(14.0)	**154.6**	(33.0)
Change in unrealized market value of financial contracts	**(11.3)**	28.0	**(5.5)**	92.8
Post-employment benefits	**(0.6)**	(0.5)	**0.2**	1.0
Change in non-cash working capital (Note 14)	**37.5**	37.1	**39.6**	(75.1)
Cash flow from operations	**138.0**	143.8	**258.8**	157.0
Interest paid[1]	**(31.6)**	(32.5)	**(32.4)**	(33.6)
Income taxes paid	**-**	6.6	**(2.6)**	5.8
Net cash flow provided by operating activities	**106.4**	117.9	**223.8**	129.2
INVESTING ACTIVITIES				
Purchase of property, plant and equipment and intangibles[1]	**(85.6)**	(78.9)	**(165.3)**	(168.1)
Cash flow used in investing activities	**(85.6)**	(78.9)	**(165.3)**	(168.1)
FINANCING ACTIVITIES				
Repayment of short-term debt	**(404.8)**	(60.0)	**(882.4)**	(119.9)
Proceeds of short-term debt	**266.7**	40.0	**674.6**	129.9
Repayment of long-term debt	**(328.5)**	(26.1)	**(336.7)**	(34.0)
Proceeds of long-term debt	**478.8**	-	**478.8**	-
Dividend paid (Note 13)	**(10.0)**	(12.0)	**(20.0)**	(24.0)
Cash flow provided by (used in) financing activities	**2.2**	(58.1)	**(85.7)**	(48.0)
Increase (decrease) in cash and cash equivalents	**23.0**	(19.1)	**(27.2)**	(86.9)
Cash and cash equivalents, beginning of period	**31.0**	49.7	**81.2**	117.5
CASH AND CASH EQUIVALENTS, END OF PERIOD[2]	**54.0**	30.6	**54.0**	30.6
Cash and cash equivalents consist of:				
Cash	**54.0**	30.6	**54.0**	30.6

(1) Total interest paid during the three and six months ended June 30, 2018 was $33.5 million and $35.8 million, respectively (2017 - $34.2 million and and $36.8 million). Purchase of PPE and intangibles includes $1.3 million and $2.7 million of capitalized borrowing costs in the three and six months ended June 30, 2018, respectively (2017 - $1.7 million and $3.2 million).

(2) Cash and cash equivalents include restricted cash of $29.8 million (December 31, 2017 - $6.7 million) relating to margin posted with a financial institution. This margin is required as part of the Corporation's commodity trading activity.

See accompanying notes to the Condensed Consolidated 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 Corporations Act* (Alberta) in July 1997 to carry on the electric utility transmission and distribution operations previously performed 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. Since 1998, the Corporation has grown from its transmission and distribution roots to include electricity generation, commercial and residential solar, electricity and natural gas retail businesses.

The Corporation's registered and head office is at 141 - 50 Avenue SE, Calgary AB, T2G 4S7. The Corporation's principal place of business is Alberta.

2. BASIS OF PREPARATION

These unaudited condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standards (IAS) 34, *Interim Financial Reporting*, and have been prepared following the same accounting policies and methods as those used in preparing the most recent consolidated financial statements, except as outlined in notes 3 and 4. These unaudited condensed consolidated interim financial statements have been prepared under the historical costs basis, except for certain financial instruments which are stated at fair value. These unaudited condensed consolidated financial statements do not include all disclosure required for the preparation of audited annual financial statements. Accordingly, these unaudited condensed consolidated financial statements should be read in conjunction with the 2017 audited annual consolidated financial statements, which are available on ENMAX's website at www.enmax.com.

These condensed consolidated interim financial statements were authorized for issuance by the Board of Directors on August 22, 2018.

3. CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of these unaudited condensed consolidated interim financial statements requires management to select appropriate accounting policies and to make judgments, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, as well as to disclose contingent assets and liabilities. These estimates and judgments concern matters that are inherently complex and uncertain. Judgments and estimates are continually evaluated and are based on historical experience and expectations of future events. Changes to accounting estimates are recognized prospectively.

Significant judgments and estimates are required in the application of accounting policies. The following table outlines new significant accounting judgments for the period start January 1, 2018, reflecting the implementation of the new accounting standards in note 4:

SIGNIFICANT ACCOUNTING JUDGMENTS

Financial Statement Area	Judgment Areas
Accounts receivables	Assumptions as input to calculate the expected loss rates.
Revenue	Contributions In Aid of Construction (CIAC) are contributions received for work performed under various statutory requirements not for the purpose of providing financing, therefore is determined not to contain significant financing component. The evaluation of principal vs. agent factors for each revenue stream.

4. ADOPTION OF NEW ACCOUNTING STANDARDS

The following standards have been adopted by ENMAX for the first time for the financial year beginning on January 1, 2018 and have the following impact.

IFRS 9, *Financial Instruments* replaces IAS 39

IFRS 9 provides guidance and requirements on classification and measurement of financial assets and liabilities, impairment and hedging. The Corporation adopts IFRS 9 with exception of the hedge accounting where ENMAX will continue to follow IAS 39 guidance on hedge accounting. The standard has introduced a single expected credit loss model for all financial assets measured at amortized cost and fair value through OCI. The Corporation was required to revise its impairment methodology under IFRS 9 over the accounts receivable for sales of commodity, transmission service, distribution service and other services and has adopted full retrospective approach, without restating prior years.

The expected credit loss allowance calculated as at January 1, 2018 is $20.0 million, which represents an increase of $1.4 million to the allowance as previously presented.

As at January 1, 2018 *(millions of Canadian dollars)*	Current	More than 30 days past due	More than 60 days past due	More than 90 days past due	Total
Expected loss rate	1.2%	24.1%	52.9%	80.6%	
Gross carrying amount	347.4	5.4	1.7	17.0	371.5
Loss allowance	4.1	1.3	0.9	13.7	20.0

ELECTED PRACTICAL EXPEDIENTS

Simplified impairment approach on accounts receivables

The Corporation calculates the expected credit losses on accounts receivable using a provision matrix which is based on the Corporation's historical credit loss experience for accounts receivables to estimate the lifetime expected credit losses. The provision matrix specifies fixed provision rates depending on the number of days that a trade receivable is past due.

IFRS 15, *Revenue from Contracts with Customers*

IFRS 15 provides a framework that replaces existing revenue recognition guidance. ENMAX applies 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.

ELECTED PRACTICAL EXPEDIENTS

Right to invoice

ENMAX applies the practical expedient to provide limited disclosure on the transaction price of its performance obligation as ENMAX either has the right to consideration from its customers in the amount that corresponds directly with the value to the customers of ENMAX's performance completed to date, or ENMAX expects the performance obligation will be satisfied within one year or less.

The existence of a significant financing component

ENMAX applies the practical expedient not to adjust its revenue for the effect of a significant financing component if ENMAX expects, at contract inception, that the period between when ENMAX transfers a promised good or service to a customer and when the customer pays for that good or service will be one year or less.

IMPACT OF CHANGE IN ACCOUNTING POLICY ON CONSOLIDATED STATEMENTS OF EARNINGS:

(millions of Canadian dollars)		**Year ended December 31, 2017 originally disclosed**	**IFRS 15 adoption**	**Year ended December 31, 2017 as presented**
REVENUE				
Electricity	**(a)**	1,687.3	(771.9)	915.4
Natural gas	**(a)**	443.5	(254.5)	189.0
Transmission and distribution		594.4	-	594.4
Local access fees		95.8	-	95.8
Other revenue		176.0	-	176.0
TOTAL REVENUE		2,997.0	(1,026.4)	1,970.6
COST OF SERVICES PROVIDED				
Electricity and fuel purchases	**(a)**	1,559.6	(771.9)	787.7
Natural gas and delivery	**(a)**	389.3	(254.5)	134.8
Transmission and distribution		333.2	-	333.2
Local access fees		95.8	-	95.8
Depreciation and amortization		224.9	-	224.9
Impairment		10.3	-	10.3
Other Expenses		453.0	-	453.0
TOTAL OPERATING EXPENSES		3,066.1	(1,026.4)	2,039.7
OPERATING (LOSS)		(69.1)	-	(69.1)

EXPLANATION OF THE MEASUREMENT ADJUSTMENTS IN THE TABLE ABOVE

(a) Revenue and cost of services provided for electricity and natural gas

Under IFRS 15, when another party is involved in providing goods or services to a customer, ENMAX shall determine whether the nature of its promise is a performance obligation to provide the specified goods or services itself (ENMAX is the principal) or to arrange for those goods or services to be provided by the other party (ENMAX is the agent).

ENMAX is a principal in relation to the performance obligations to provide: supplies of commodity, transmission service, distribution service and service to maintain or develop a customer’s asset. ENMAX is an agent in relation to the performance obligation to arrange for the delivery of commodity to the customers' specified locations and therefore the payment and the recovery of such flow-through costs were revised to be presented as net.

CHANGES TO SIGNIFICANT ACCOUNTING POLICIES DUE TO ADOPTION OF NEW ACCOUNTING STANDARDS

(a) FINANCIAL INSTRUMENTS

Classification

The financial assets of the Corporation are classified in the following categories:

- Amortized cost: assets that are held for collection of contractual cash flows where those cash flows represent solely payments of principal and interest are measured at amortized cost. Financial assets of the Corporation included in this category are cash and cash equivalents, and current and long-term accounts receivables.
- Fair value through other comprehensive income (FVOCI): assets that are held for collection of contractual cash flows and for selling the financial assets, where the assets' cash flows represent solely payments of principal and interest, are measured at FVOCI. Financial assets of the Corporation included in this category are equity investments.
- Fair value through profit or loss: assets that do not meet the criteria for amortized cost or FVOCI are measured at fair value through earnings. Financial assets of the Corporation included in this category are derivative instruments.

The financial liabilities of the Corporation are all classified as amortized cost, except for financial liabilities at fair value through profit or loss. Financial liabilities of the Corporation included under amortized cost are accounts payables, current and long-term debt, deferred revenues and other current and other long-term liabilities. Financial liabilities of the Corporation included under fair value through profit or loss are derivative instruments.

Impairment of financial assets

The impairment provisions for accounts receivable disclosed at note 7 are based on assumptions on expected loss rates. The Corporation uses judgement in making these assumptions and selecting the inputs to the impairment calculation, based on the Corporation's past history, existing market conditions as well as forward looking estimates at the end of the each reporting period.

Derivatives and hedging activities

Derivatives are initially recognized at fair value on the date a derivative contract is entered into and are subsequently remeasured to their fair value at the end of each reporting period. The accounting for subsequent changes in fair value depends on whether the derivative is designated as a hedging instrument, and if so, the nature of the item being hedged and the type of hedge relationship designated.

The fair values of various derivative financial instruments used for hedging purposes are disclosed in note 7. Movements in the hedging reserve in shareholder's equity are shown in note 11. The full fair value of a hedging derivative is classified as a non-current asset or liability when the remaining maturity of the hedged item is more than 12 months; it is classified as a current asset or liability when the remaining maturity of the hedged item is less than 12 months. Trading derivatives are classified as current assets or liabilities.

Cash flow hedges

The Corporation utilizes forward and swap contracts as hedging instruments to manage the commodity price risk associated with its highly probable commodity sales and purchases. The Corporation documents at the inception of the hedging transaction the economic relationship between hedging instruments and hedged items including whether the hedging instrument is expected to offset changes in cash flows of hedged items.

Sources of hedge ineffectiveness can occur as a result of credit risk, change in hedge ratio and forecast adjustments leading to over-hedging. If the hedge ratio for risk management purposes is no longer optimal but the risk management objective remains unchanged and the hedge continues to qualify for hedge accounting, the hedge relationship will be rebalanced by adjusting either the volume of the hedging instrument or the volume of the hedged item so that the hedge ratio aligns with the ratio used for risk management purposes. Any hedge ineffectiveness is calculated and accounted for in earnings at the time of the hedge relationship rebalancing.

The Corporation can only discontinue hedge accounting prospectively if there is no longer an economic relationship between the hedged item and hedging instrument, the risk management objective changes, the derivative no longer is designated as a hedging instrument or the underlying hedged item is derecognized. If the Corporation discontinues hedge accounting, the cumulative gain or loss in AOCI is transferred to earnings at the same time as the hedged item affects earnings. The amount in AOCI is immediately transferred to earnings if the hedged item is derecognized or it is probable that a forecast transaction will not occur in the originally specified time frame.

(b) REVENUE RECOGNITION

Revenue is recognized when the Corporation satisfies a performance obligation by transferring a promised good or service to a customer and the amount recorded corresponds to the value that ENMAX expects to be entitled to. An asset is transferred when the customer obtains control of that asset. Revenue is measured at the fair value of the consideration received and is reduced for rebates and other similar allowances.

Practical expedients

ENMAX applied the following practical expedients:

- No disclosure on transaction price for unsatisfied performance obligations as a result of the ability to invoice the customer in amounts that correspond to the value that the customer receives; and
- No adjustment to transaction price due to significant financing component.

Electricity and gas

Contracts with customers within the Competitive Energy operation mainly consist of contracts to provide and deliver supplies of electricity and/or natural gas ('the commodity') to customers' specified locations.

Performance obligations

Typical commodity contracts with customers include two performance obligations, which are to provide supplies of the commodity and to arrange for the delivery of these supplies to the customers' specified locations. These performance obligations are considered to be a series of performance obligations satisfied over time as the customers simultaneously consume the commodity and generate benefits upon receipt. The method of recognition of revenue for the commodity is an output method, which is based on volume of commodity delivered to the customers.

As required under IFRS 15, ENMAX performed the principal versus agent assessment and treatment of delivery charges collected within the Calgary city limit does not change under IFRS 15 as ENMAX is considered a principal for the provision of supplies of the commodity, with these charges reflected as gross revenue on ENMAX's condensed consolidated interim financial statements. For delivery charges outside the Calgary city limit, ENMAX is an agent in relation to the performance obligation to arrange for delivery of the commodity and therefore the payment and recovery of the flow-through costs are presented on a net basis.

Transaction price

The transaction price for the commodity contract involves consideration from customers that is variable and constrained due to unknown volume of the commodity that will be consumed. Certain commodity contracts may also include a price constraint as the relevant commodity price would be based on the commodity pool price at the time of the consumption. The variable consideration is no longer constrained when the volume and/or price of the commodity consumed by customers become known at each period. The resolved transaction price for the commodity delivered to customer at each billing period will be allocated to the single performance obligation to provide the commodity.

Revenue recognition

The method utilized to recognize revenue for a commodity contract is an output method, which is based on actual volume of commodity distributed each period.

Transmission and distribution

Contracts with customers under transmission and distribution operations are ENMAX's promises to provide transmission and distribution services to end customers through collaboration with electricity retailers. The customer for transmission service is the Alberta Electric System Operator (AESO), while the customers for the distribution service are electricity retailers.

Performance obligation

The transmission contract includes one performance obligation, which is a stand-ready obligation to provide transmission service for the period. This performance obligation is satisfied when the stand-ready obligation to provide transmission service has been performed each month. The distribution contract includes one performance obligation, which is to provide distribution services. This performance obligation is satisfied when the end customer receives electricity. ENMAX promises to provide transmission and distribution services to the customer are performance obligations that are satisfied over time as the customer is able to simultaneously consume the electricity transmitted and distributed to the customer's location.

Transaction price

The transaction price for the transmission service involves consideration that is variable and constrained. The variable consideration is no longer constrained when AUC approves the Cost of Service which allows the Corporation to recover the cost to build, operate and maintain the transmission lines.

The transaction price for the distribution contract involves consideration that is variable and constrained. The variable consideration is no longer constrained when the actual number of customers serviced during each billing period becomes known.

Revenue recognition

The method utilized to recognize revenue for the transmission contract is an input method, which is based on the passage of time as the stand-ready performance obligation is completed each period. The method utilized to recognize revenue for the distribution contract is an output method, which is based on actual volume of electricity distributed and actual number of customers serviced each period.

Contractual services

Contracts with a customer where ENMAX promises to render services mainly consist of services to maintain customer’s assets or to develop specific assets.

Performance obligation

The rendering of a service contract includes one performance obligation, which is to either maintain customer's assets or to develop an asset. This performance obligation is satisfied over time either because the customer simultaneously benefits from the maintenance services completed or because the service provided either enhances the customer's assets or the new assets are highly specific for the customer and ENMAX has the right to receive payment for all the services performed at the end of each reporting period.

Transaction price

The transaction price for the rendering of a services contract includes consideration from the customer that is fixed. Certain contracts may also include variable considerations that are constrained, hence are not included in the transaction prices. The transaction price for all services rendered to the customer at each billing period will be allocated to the single performance obligation to provide a service to the customer.

Revenue recognition

Both input and output methods are used to recognize revenue for the rendering of service contracts depending on which method more accurately depicts ENMAX's promise to transfer services to the customer. For contracts where an input method is used, revenue is recognized based on actual labor cost and materials consumed to perform the required service during each billing period. For contracts where an output method is used, the revenue is recognized based on actual services delivered to the customer during each billing period.

5. ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

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

IFRS 16 *Leases*

The new leases standard requires companies to bring most leases onto the balance sheet and eliminates the distinction between operating and finance leases. The key objective of the new standard is to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The standard is effective January 1, 2019. Early application is permitted for companies that also apply IFRS 15 *Revenue from Contracts with Customers*. The Corporation is currently assessing the impact of adopting this standard and plans to fully implement it effective January 1, 2019.

6. SEGMENT INFORMATION

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

The Corporation uses a shared service allocation model to allocate cost between segments.

ENMAX COMPETITIVE ENERGY (COMPETITIVE ENERGY)

Competitive Energy is an operating segment established to carry out competitive energy supply and retail functions through various legal entities and affiliated companies. The Competitive Energy integrated strategy is to provide customers with competitive energy products and services with a focus on longer-term fixed electricity contracts. Competitive Energy products deliver solutions to serve increasing desire from customers for simple access to reliable low cost sustainable energy (i.e., distributed energy assets and services). Competitive Energy also delivers project execution for customer infrastructure in areas such as power infrastructure, light rail transit and commercial, residential development.

ENMAX POWER DELIVERY (POWER DELIVERY)

Power Delivery is a regulated operating segment established to carry out electricity transmission and distribution service functions and the Regulated Rate Option (RRO) retail function through legal entities and affiliated companies.

SEGMENTED TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT BALANCES

As at *(millions of Canadian dollars)*	**June 30, 2018**	**December 31, 2017**
Competitive Energy	**2,774.0**	2,935.3
Power Delivery	**2,466.9**	2,410.6
Corporate and Eliminations	**136.4**	149.0
Total Assets	**5,377.3**	5,494.9
Regulatory deferral account debit balances	**92.6**	76.2
Total assets and regulatory deferral account debit balances	**5,469.9**	5,571.1

COMPARATIVE SEGMENT INFORMATION

Segment information reflects the presentation regularly reviewed by the chief operating decision maker. The chief operating decision maker uses adjusted operating profit as the basis for making decisions around asset allocation or assessing performance. Adjusted operating profit adjusts for items such as impairment, foreign exchange onerous provision charges on long-term contracts, and unrealized gains and losses on commodities and is reflected in the column 'Adjusted Consolidated Totals' below.

Three months ended June 30, 2018 *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate and Eliminations**	**Adjusted Consolidated Totals**	**Regulatory Deferral Movement**	**Other Presentation Reclass**	**Consolidated Totals**
REVENUE							
Electricity	311.6	24.9	(19.3)	317.2	0.1	-	**317.3**
Natural gas	24.4	-	-	24.4	-	-	**24.4**
Transmission and distribution	-	159.5	-	159.5	0.5	-	**160.0**
Local access fees	-	34.2	-	34.2	-	-	**34.2**
Other revenue	52.1	9.6	(7.3)	54.4	(5.6)	-	**48.8**
TOTAL REVENUE	388.1	228.2	(26.6)	589.7	(5.0)	-	**584.7**
OPERATING EXPENSES							
Electricity and fuel purchases	248.7	19.3	(18.9)	249.1	-	(13.0)	**236.1**
Natural gas and delivery	13.5	-	0.1	13.6	-	-	**13.6**
Transmission and distribution	-	82.8	-	82.8	12.7	-	**95.5**
Local access fees	-	34.2	-	34.2	-	-	**34.2**
Depreciation and amortization	27.7	25.5	3.2	56.4	-	-	**56.4**
Other expenses	94.1	39.2	(8.6)	124.7	(4.9)	(5.4)	**114.4**
TOTAL OPERATING EXPENSES	384.0	201.0	(24.2)	560.8	7.8	(18.4)	**550.2**
OPERATING PROFIT (LOSS)	4.1	27.2	(2.4)	28.9	(12.8)	18.4	**34.5**
Unrealized gains on commodities				(13.0)	-	13.0	**-**
Foreign exchange gains				(5.4)	-	5.4	**-**
Finance charges				17.9	-	-	**17.9**
NET EARNINGS BEFORE TAX				29.4	(12.8)	-	**16.6**
Current income tax expense				0.2	-	-	**0.2**
Deferred income tax recovery				(5.7)	-	-	**(5.7)**
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL				34.9	(12.8)	-	**22.1**
NET MOVEMENT IN REGULATORY DEFERRAL				-	12.8	-	**12.8**
NET EARNINGS				34.9	-	-	**34.9**

Three months ended June 30, 2017 *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate and Eliminations**	**Adjusted Consolidated Totals**	**Regulatory Deferral Movement**	**Other Presentation Reclass**	**Consolidated Totals**
REVENUE							
Electricity	207.5	13.4	(8.0)	212.9	(1.1)	-	**211.8**
Natural gas	32.5	-	0.1	32.6	-	-	**32.6**
Transmission and distribution	-	145.4	-	145.4	0.2	-	**145.6**
Local access fees	-	23.4	-	23.4	-	-	**23.4**
Other revenue	37.3	7.7	(5.8)	39.2	(4.8)	-	**34.4**
TOTAL REVENUE	277.3	189.9	(13.7)	453.5	(5.7)	-	**447.8**
OPERATING EXPENSES							
Electricity and fuel purchases	137.0	7.9	(7.6)	137.3	-	22.9	**160.2**
Natural gas and delivery	22.2	-	-	22.2	-	-	**22.2**
Transmission and distribution	-	74.5	-	74.5	15.4	-	**89.9**
Local access fees	-	23.4	-	23.4	-	-	**23.4**
Depreciation and amortization	28.8	23.4	2.6	54.8	-	-	**54.8**
Other expenses	79.5	37.6	(7.4)	109.7	(4.0)	5.8	**111.5**
TOTAL OPERATING EXPENSES	267.5	166.8	(12.4)	421.9	11.4	28.7	**462.0**
OPERATING PROFIT (LOSS)	9.8	23.1	(1.3)	31.6	(17.1)	(28.7)	**(14.2)**
Unrealized losses on commodities				22.9	-	(22.9)	**-**
Foreign exchange losses				5.8	-	(5.8)	**-**
Finance charges				17.8	-	-	**17.8**
NET LOSS BEFORE TAX				(14.9)	(17.1)	-	**(32.0)**
Current income tax expense				1.8	-	-	**1.8**
Deferred income tax recovery				(15.8)	-	-	**(15.8)**
NET LOSS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL				(0.9)	(17.1)	-	**(18.0)**
NET MOVEMENT IN REGULATORY DEFERRAL				-	17.1		**17.1**
NET LOSS				(0.9)	-	-	**(0.9)**

Six months ended June 30, 2018 *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate and Eliminations**	**Adjusted Consolidated Totals**	**Regulatory Deferral Movement**	**Other Presentation Reclass**	**Consolidated Totals**
REVENUE							
Electricity	579.2	46.6	(36.2)	589.6	0.2	-	**589.8**
Natural gas	99.2	-	(0.1)	99.1	-	-	**99.1**
Transmission and distribution	-	320.4	-	320.4	(0.3)	-	**320.1**
Local access fees	-	63.6	-	63.6	-	-	**63.6**
Other revenue	84.2	18.9	(14.8)	88.3	(5.9)	-	**82.4**
TOTAL REVENUE	762.6	449.5	(51.1)	1,161.0	(6.0)	-	**1,155.0**
OPERATING EXPENSES							
Electricity and fuel purchases	437.5	35.9	(35.5)	437.9	-	(2.8)	**435.1**
Natural gas and delivery	67.8	-	0.2	68.0	-	-	**68.0**
Transmission and distribution	-	167.9	-	167.9	15.6	-	**183.5**
Local access fees	-	63.6	-	63.6	-	-	**63.6**
Depreciation and amortization	55.7	51.2	6.5	113.4	-	-	**113.4**
Other expenses	171.6	80.0	(16.0)	235.6	(5.0)	(24.2)	**206.4**
TOTAL OPERATING EXPENSES	732.6	398.6	(44.8)	1,086.4	10.6	(27.0)	**1,070.0**
OPERATING PROFIT (LOSS)	30.0	50.9	(6.3)	74.6	(16.6)	27.0	**85.0**
Unrealized gains on commodities				(2.8)	-	2.8	**-**
Foreign exchange gains				(11.7)	-	11.7	**-**
Recovery of onerous provision				(12.5)	-	12.5	**-**
Finance charges				35.2	-	-	**35.2**
NET EARNINGS BEFORE TAX				66.4	(16.6)	-	**49.8**
Current income tax expense				133.6	-	-	**133.6**
Deferred income tax expense				21.0	-	-	**21.0**
NET LOSS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL				(88.2)	(16.6)	-	**(104.8)**
NET MOVEMENT IN REGULATORY DEFERRAL				-	16.6	-	**16.6**
NET LOSS				(88.2)	-	-	**(88.2)**

Six months ended June 30, 2017 *(millions of Canadian dollars)*	Competitive Energy	Power Delivery	Corporate and Eliminations	Adjusted Consolidated Totals	Regulatory Deferral Movement	Other Presentation Reclass	Consolidated Totals
REVENUE							
Electricity	445.1	31.0	(20.2)	455.9	(2.7)	-	**453.2**
Natural gas	113.5	-	-	113.5	-	-	**113.5**
Transmission and distribution	-	282.6	-	282.6	(0.4)	-	**282.2**
Local access fees	-	48.7	-	48.7	-	-	**48.7**
Other revenue	83.8	15.7	(11.0)	88.5	(9.1)	-	**79.4**
TOTAL REVENUE	642.4	378.0	(31.2)	989.2	(12.2)	-	**977.0**
OPERATING EXPENSES							
Electricity and fuel purchases	291.5	19.9	(21.0)	290.4	-	85.5	**375.9**
Natural gas and delivery	84.8	-	0.1	84.9	-	-	**84.9**
Transmission and distribution	-	139.9	-	139.9	32.8	-	**172.7**
Local access fees	-	48.7	-	48.7	-	-	**48.7**
Depreciation and amortization	57.6	46.4	5.4	109.4	-	-	**109.4**
Other expenses	162.2	78.2	(14.7)	225.7	(8.4)	5.4	**222.7**
TOTAL OPERATING EXPENSES	596.1	333.1	(30.2)	899.0	24.4	90.9	**1,014.3**
OPERATING PROFIT (LOSS)	46.3	44.9	(1.0)	90.2	(36.6)	(90.9)	**(37.3)**
Unrealized losses on commodities				85.5	-	(85.5)	**-**
Foreign exchange losses				5.4	-	(5.4)	**-**
Finance charges				35.7	-	-	**35.7**
NET LOSS BEFORE TAX				(36.4)	(36.6)	-	**(73.0)**
Current income tax expense				3.3	-	-	**3.3**
Deferred income tax recovery				(36.3)	-	-	**(36.3)**
NET LOSS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL				(3.4)	(36.6)	-	**(40.0)**
NET MOVEMENT IN REGULATORY DEFERRAL				-	36.6	-	**36.6**
NET LOSS				(3.4)	-	-	**(3.4)**

REVENUE

Types of Customers and Sales Channel	Nature and significant payment terms
Mass market	Mass Market is comprised of residential and small business customers who consume less than 250,000 kWh/year. These customers can be supplied electricity through competitive contracts or through the Regulated Rate Option. Natural gas is always supplied under a competitive contract.
Commercial market	Commercial Market is business to business competitive contracting for electricity and/or natural gas. A small number of commercial customers that do not negotiate a contract are supplied electricity on a regulated Default supply.
Government and institutional	ENMAX receives revenue from governments and municipalities (counties, cities and towns), entities backed by the government, universities, colleges and school boards.
Non-government and non-institutional	ENMAX receives revenue from individual consumers to large corporations; these individuals and corporations receive credit and terms based on the revenue product and their credit history.
Transmission	ENMAX receives revenue from Alberta Electric System Operator (AESO) specifically for the use of its transmission grid system.
Distribution	ENMAX receives revenue from electricity retailers specifically for the utilization of its electricity distribution system in delivering electricity to the end customers.
City of Calgary local access fees	ENMAX receives revenue from electricity end users to offset municipal levies by the City of Calgary in lieu of property taxes.

REVENUE – MAJOR CUSTOMERS AND SALES CHANNELS

(millions of Canadian dollars)	Mass Market	Commercial Market	Government and Institutional	Non-Government and Non-Institutional	Transmission	Distribution	City of Calgary Local Access Fees	Total
Three months ended June 30, 2018								
Electricity								
Competitive Energy	51.5	231.3	-	-	-	-	-	**282.8**
Regulated	28.4	6.1	-	-	-	-	-	**34.5**
Natural gas	18.3	6.1	-	-	-	-	-	**24.4**
Transmission & distribution	-	-	-	-	22.9	137.1	-	**160.0**
Local access fees	-	-	-	-	-	-	34.2	**34.2**
Other revenue	-	-	-	2.0	-	-	-	**2.0**
Contractual services	-	-	16.0	30.8	-	-	-	**46.8**
TOTAL REVENUE	**98.2**	**243.5**	**16.0**	**32.8**	**22.9**	**137.1**	**34.2**	**584.7**
Three months ended June 30, 2017								
Electricity								
Competitive Energy	43.5	148.6	-	-	-	-	-	**192.1**
Regulated	15.1	5.6	-	-	-	-	-	**20.7**
Natural gas	23.7	8.9	-	-	-	-	-	**32.6**
Transmission & distribution	-	-	-	-	18.5	127.1	-	**145.6**
Local access fees	-	-	-	-	-	-	23.4	**23.4**
Other revenue	-	-	-	1.1	-	-	-	**1.1**
Contractual services	-	-	8.1	24.2	-	-	-	**32.3**
TOTAL REVENUE	**82.3**	**163.1**	**8.1**	**25.3**	**18.5**	**127.1**	**23.4**	**447.8**

(millions of Canadian dollars)	Mass Market	Commercial Market	Government and Institutional	Non-Government and Non-Institutional	Transmission	Distribution	City of Calgary Local Access Fees	Total
Six months ended June 30, 2018								
Electricity								
Competitive Energy	108.3	418.2	-	-	-	-	-	**526.5**
Regulated	52.7	10.6	-	-	-	-	-	**63.3**
Natural gas	72.6	26.5	-	-	-	-	-	**99.1**
Transmission & distribution	-	-	-	-	41.3	278.8	-	**320.1**
Local access fees	-	-	-	-	-	-	63.6	**63.6**
Other revenue	-	-	-	11.3	-	-	-	**11.3**
Contractual services	-	-	26.0	45.1	-	-	-	**71.1**
TOTAL REVENUE	**233.6**	**455.3**	**26.0**	**56.4**	**41.3**	**278.8**	**63.6**	**1,155.0**

(millions of Canadian dollars)	Mass Market	Commercial Market	Government and Institutional	Non-Government and Non-Institutional	Transmission	Distribution	City of Calgary Local Access Fees	Total
Six months ended June 30, 2017								
Electricity								
Competitive Energy	99.1	307.8	-	-	-	-	-	**406.9**
Regulated	34.5	11.8	-	-	-	-	-	**46.3**
Natural gas	82.2	31.3	-	-	-	-	-	**113.5**
Transmission & distribution	-	-	-	-	37.0	245.2	-	**282.2**
Local access fees	-	-	-	-	-	-	48.7	**48.7**
Other revenue	-	-	-	11.2	-	-	-	**11.2**
Contractual services	-	-	17.5	50.7	-	-	-	**68.2**
TOTAL REVENUE	**215.8**	**350.9**	**17.5**	**61.9**	**37.0**	**245.2**	**48.7**	**977.0**

7. FINANCIAL INSTRUMENTS, HEDGES AND RISK MANAGEMENT MARKET RISK

MARKET RISK

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. This includes managing its 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.

VALUATION OF DERIVATIVE ASSETS AND LIABILITIES

Financial derivative instruments are recorded at fair value on the statement of financial position. As at June 30, 2018, the fair values of derivatives were as follows:

As at	June 30, 2018		December 31, 2017	
(millions of Canadian dollars)	Hedge Instruments	Non-Hedge Derivatives	Hedge Instruments	Non-Hedge Derivatives
Assets				
Current	**53.8**	**50.0**	44.6	54.3
Non-current	**42.1**	**14.1**	38.3	11.1
Liabilities				
Current	**12.2**	**100.6**	18.1	123.7
Non-current	**17.6**	**122.0**	35.6	105.7

For cash flow hedges, gains and losses are reclassified immediately to net earnings when anticipated hedged transactions are no longer likely to occur. During Q4 2016, the Corporation voluntarily de-designated a portion of its cash flow hedges. At the time of de-designation, the accumulated gain in OCI was $8.8 million and is currently being reclassified to net earnings in the same period as the anticipated hedge transactions settle or when deemed ineffective. During the three and six months ended June 30, 2018, there was a $nil and $nil, impact recognized in electricity and fuel purchases (2017 - $nil and $3.3 million) as a reflection of the ineffectiveness of the relevant hedges.

For non-hedge derivatives, there were unrealized gains of $11.4 and $5.5 million for the three months and six months ended June 30, 2018, respectively, (2017 - $28.0 million loss and $92.8 million loss), primarily recorded in electricity and fuel purchases. The anticipated non-hedge derivatives are expected to settle in 2018 through 2024. The mark-to-market adjustments do not consider the impact of any interrelationship among the factors such as the underlying position and the optionality of the Corporation's integrated business. Generation capacity or future sales to customers are not mark-to-market, which creates a mismatch in the timing of earnings.

NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES

Fair values for cash and cash equivalents, accounts receivable, short-term financing, 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	**June 30, 2018**		**December 31, 2017**	
(millions of Canadian dollars)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt [1] consisting of:				
Debentures, with remaining terms of:				
Less than 5 years	**72.7**	**74.2**	73.0	75.3
5 - 10 years	**22.2**	**23.2**	12.6	13.3
10 - 15 years	**154.5**	**172.1**	111.9	125.6
15 - 20 years	**518.1**	**554.8**	465.7	509.0
20 - 25 years	**455.0**	**462.1**	415.4	424.3
Private debentures:				
Series 1 (6.15%)	**-**	**-**	299.7	307.1
Series 3 (3.81%)	**199.0**	**205.6**	198.9	204.5
Series 4 (3.84%)	**298.2**	**302.9**	-	-
Promissory note	**3.4**	**3.6**	3.6	3.8
	1,723.1	**1,798.5**	1,580.8	1,662.9

[1] Includes current portion of $75.3 million (December 31, 2017 – $367.3 million). Maturity dates range from June 2018 to June 2043.

As at June 30, 2018, ENMAX had $nil with a fair value of $nil of commercial paper (December 31, 2017 - $207.7 million, fair value of $207.7 million with an average rate of 1.40 per cent).

8. REGULATORY DEFERRAL ACCOUNT BALANCES

NATURE AND ECONOMIC EFFECT OF RATE REGULATION

ENMAX Transmission and ENMAX Distribution ('the Divisions') are divisions of ENMAX Power Delivery segment. The Divisions are regulated operations established to carry out all electrical transmission and distribution service functions in its own right. The AUC approves the Division's Transmission and Distribution Tariffs (rates and terms and conditions of service) subject to Sections 37 and 102 of the Electric Utilities Act.

REGULATORY 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 deferral account debit and credit balances:

As at *(millions of Canadian dollars)*	**Accounts Receivable (a)**	**Un-Eliminated Inter-Company Profit (b)**	**Other Regulatory Debits (c)**	**Total Regulatory Deferral Account Debit Balances**
Regulatory deferral account debit balances				
January 1, 2018	34.4	9.9	31.9	76.2
Balances arising in the period [1]	37.0	0.2	0.4	37.6
Reversal [2]	(32.7)	-	(1.3)	(34.0)
March 31, 2018	38.7	10.1	31.0	79.8
Balances arising in the period [1]	49.2	0.8	1.3	51.3
Reversal [2]	(33.2)	-	(5.3)	(38.5)
June 30, 2018	**54.7**	**10.9**	**27.0**	**92.6**
Expected recovery/reversal period	3 Months	25 Years	12 Months	
January 1, 2017	-	8.8	31.0	39.8
Balances arising in the period [1]	83.4	0.7	1.7	85.8
Reversal [2]	(51.0)	-	(6.5)	(57.5)
June 30, 2017	32.4	9.5	26.2	68.1
Balances arising in the period [1]	83.6	0.4	15.3	99.3
Reversal [2]	(81.6)	-	(9.6)	(91.2)
December 31, 2017	34.4	9.9	31.9	76.2
Expected recovery/reversal period	2 Months	25 Years	12 Months	

[1] 'Balances arising in the period' row consist of new additions to regulatory deferral debits and credit balances.
[2] 'Reversal' row consist of amounts collected/refunded through rate riders or transactions reversing existing regulatory balances.

As at *(millions of Canadian dollars)*	**Accounts Payable (a)**	**Other Regulatory Credits (d)**	**Total Regulatory Deferral Account Credit Balances**
Regulatory deferral account credit balances			
January 1, 2018	-	9.4	9.4
Balances arising in the period [1]	-	-	-
Reversal [2]	-	(0.2)	(0.2)
March 31, 2018	-	9.2	9.2
Balances arising in the period [1]	-	-	-
Reversal [2]	-	-	-
June 30, 2018	**-**	**9.2**	**9.2**
Expected recovery/reversal period		12 Months	
January 1, 2017	4.5	13.2	17.7
Balances arising in the period [1]	-	-	-
Reversal [2]	(4.5)	(3.8)	(8.3)
June 30, 2017	-	9.4	9.4
Balances arising in the period [1]	-	0.2	0.2
Reversal [2]	-	(0.2)	(0.2)
December 31, 2017	-	9.4	9.4
Expected recovery/reversal period		12 Months	

[1] 'Balances arising in the period' row consist of new additions to regulatory deferral debits and credit balances.
[2] 'Reversal' row consist of amounts collected/refunded through rate riders or transactions reversing existing regulatory balances.

The following describes each of the circumstances in which rate regulation affects the accounting for a transaction or event. Regulatory deferral account debit balances represent 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 account 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 and payable

Accounts receivable and payable represent a deferral account for transmission charges from the AESO. In the absence of rate regulation and the standard, IFRS 14 would require that actual costs be recognized as an expense when incurred.

(b) Inter-company profit

A subsidiary of the Corporation performs construction work for the regulated operations of Power Delivery at a profit. Such profit is deemed 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 standard, IFRS would require that intercompany profits be eliminated upon consolidation.

(c) Other regulatory debits

Other regulatory debits primarily relate to the AUC flow-through items and other costs that will be collected from customers via future rates such as access service charges. The 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 including those inherent in rate-setting regulatory processes. 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.

9. OTHER ASSETS AND LIABILITIES

As at *(millions of Canadian dollars)*	June 30, 2018	December 31, 2017
Other current assets		
Prepaid expenses	**15.8**	9.1
Collateral paid	**59.2**	58.0
Deferred asset	**0.3**	0.3
Emission offsets	**43.9**	39.0
Other	**5.4**	3.0
	124.6	109.4
Other long-term assets		
Prepaid expenses	**8.6**	9.1
Long-term accounts receivable	**0.3**	0.6
Deferred asset	**3.4**	3.5
Long-term collateral paid	**4.5**	4.8
Other	**7.7**	8.1
	24.5	26.1
Other current liabilities		
Finance lease	**0.2**	0.3
Deposits	**19.2**	18.7
Other	**7.9**	8.4
	27.3	27.4
Other long-term liabilities		
Finance lease	**4.2**	4.3
Other	**8.8**	11.6
	13.0	15.9

10. INCOME TAXES

The calculation of the Corporation's current and deferred income taxes involves a degree of estimation and judgment. The carrying value of deferred income tax assets is reviewed at the end of each reporting period. For the three months and six months ended June 30, 2018, management adjusted the income tax provision utilizing its best estimate with considerations including management's expectation of future operating results, interpretation of applicable tax positions and allowances, where uncertainty surrounding the realization of the tax benefit exists.

On April 26, 2018, the Alberta Court of Appeal issued its decision allowing the Crown's appeal and reinstating the Notices of Reassessment previously issued by Alberta Finance. The Notices of Reassessment reflect a lower interest rate than provided for under the intercompany loans. As a result, we have recognized tax expenses of $164.3 million during the six months ended June 30, 2018, which reflects our current estimate of the difference in the applicable interest rates as well as interest over the affected period. ENMAX expects that there will be adjustments to this amount in future periods as the assumptions applied are refined and confirmed. A detailed description of this matter was provided in Note 25 of the Corporation's 2017 audited annual financial statements.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME

As at *(millions of Canadian dollars)*	June 30, 2018	December 31, 2017
Net unrealized gains on derivatives designated as cash flow hedges, including deferred income tax expense of $20.7 million (December 31, 2017 - expense of $11.3 million)	**45.6**	17.9
Net actuarial (losses) on defined benefit plans, including deferred income tax recovery of $0.4 million (December 31, 2017 - recovery of $0.4 million)	**(6.2)**	(6.2)
Accumulated other comprehensive income, including deferred income tax expense of $20.3 million (December 31, 2017 - expense of $10.9 million)	**39.4**	11.7

12. OTHER REVENUE AND EXPENSES

	Three months ended June 30,		Six months ended June 30	
(millions of Canadian dollars)	2018	2017	2018	2017
OTHER REVENUE				
Interest and penalty revenue	**2.1**	2.3	**4.6**	5.4
Miscellaneous	**1.0**	0.8	**4.0**	7.4
	3.1	3.1	**8.6**	12.8
OTHER EXPENSES				
Salaries and wages	**64.7**	53.2	**131.8**	116.9
Materials and supplies	**6.1**	7.4	**10.4**	15.4
Goods and services	**37.9**	24.8	**61.7**	45.5
Administrative and office expenses	**2.3**	2.9	**5.7**	5.8
Building expense	**12.4**	13.4	**21.8**	24.8
Vehicles and other	**(3.7)**	4.0	**(0.9)**	8.9
Recovery of onerous provision	**-**	-	**(12.5)**	-
Foreign exchange gains (losses)	**(5.3)**	5.8	**(11.6)**	5.4
	114.4	111.5	**206.4**	222.7

13. DIVIDENDS

On March 15, 2018, the Corporation declared a dividend of $40.0 million to the City (2017 - $48.0 million). The dividend is paid in equal quarterly instalments during 2018.

14. CHANGE IN NON-CASH WORKING CAPITAL

	Three months ended June 30,		Six months ended June 30,	
(millions of Canadian dollars)	2018	2017	2018	2017
Accounts receivable	**21.8**	75.6	**14.8**	38.4
Regulatory deferral account debit balances	**(12.8)**	(15.8)	**(16.4)**	(28.3)
Other assets	**(9.5)**	17.6	**(13.6)**	(19.1)
Accounts payable and accrued liabilities	**35.5**	(35.8)	**72.3**	(38.3)
Regulatory deferral account credit balances	**-**	(1.3)	**(0.2)**	(8.3)
Other liabilities	**2.0**	(2.2)	**(3.1)**	(18.0)
Provisions	**0.5**	(1.0)	**(14.2)**	(1.5)
Change in non-cash working capital	**37.5**	37.1	**39.6**	(75.1)

15. RELATED PARTY TRANSACTIONS

The City is the sole shareholder of the Corporation. The following tables summarize the related party transactions between the Corporation and the City.

STATEMENTS OF EARNINGS

	Three months ended June 30,		Six months ended June 30,	
(millions of Canadian dollars)	**2018**	**2017**	**2018**	**2017**
Revenue [1]	**40.5**	32.3	**76.3**	68.0
Local access fees and other expenses [2]	**34.6**	24.9	**65.7**	52.3

[1] 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.
[2] This cost is passed through the Corporation directly to transmission and distribution customers.

STATEMENTS OF FINANCIAL POSITION

As at *(millions of Canadian dollars)*	**June 30, 2018**	**December 31, 2017**
Accounts receivable	**32.3**	36.0
Other long-term assets	**-**	0.6
Property, plant and equipment[1]	**3.5**	3.6
Accounts payable and accrued liabilities	**13.9**	9.4
Dividends payable	**20.0**	-
Long-term debt[2]	**1,222.5**	1,078.5
Other long-term liabilities[3]	**6.5**	6.7

[1] Assets under lease.
[2] Interest and principal payments for the three months and six months ended June 30, 2018 were $19.3 million (2017 - $20.1 million) and $20.4 million (2017 - $21.6 million) respectively. In addition, for the three months and six months ended June 30, 2018, the Corporation paid a management fee of $0.7 million (2017 - $0.7 million) and $1.4 million (2017 - $1.4 million) respectively, to the City.
[3] Finance lease obligation.

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

The Corporation has committed to a water supply agreement, whereby the City supplies a specified amount of water annually to facilitate Shepard Energy Centre operations.

16. COMMITMENTS AND CONTINGENCIES

The Corporation is committed to expenditures for capital additions, rent for premises, vehicles and equipment under multiple lease contracts with varying expiration dates.

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

HISTORICAL TRANSMISSION LINE LOSS CHARGES

The Corporation is participating in various proceedings regarding the AESO's Line Loss Rule (LLR). The LLR establishes the loss factors that form the basis for certain transmission charges paid by Alberta generators, including ENMAX. Proceedings relating to the LLR address the AUC's authority to order retroactive adjustments (Module A); the replacement of the 2006-2016 methodology (Module B); and the calculation and payment of retroactive loss charges and credits for the 2006-2016 period (Module C). The AUC issued its decision on the last module, Module C, on December 18, 2017. The AUC's decisions in each of Module A, B and C are the subject of permission to appeal applications before the Alberta Court of Appeal as well as review and variance applications before the AUC.

No provision has been recognized with respect to the above matter at this time as, with respect to currently held assets, the amount owing is expected to be $nil.

LEGAL AND REGULATORY PROCEEDINGS

In the normal course of business, the Corporation is and may be named as a defendant or party in lawsuits and regulatory proceedings related to various matters. The Corporation currently believes the outcome of these lawsuits and regulatory proceedings will not have a material impact on the operating results or financial position of the Corporation.

The Corporation, along with other market participants in the province of Alberta, is subject to decisions, market rules, regulations, regulatory proceedings and/or jurisdiction of the AUC, AESO, Market Surveillance Administrator (MSA) and other authorities. The financial impact of decisions, market rules, regulations and regulatory proceedings is reflected in the consolidated financial statements when the amount can be reasonably estimated.

ONEROUS PROVISION SETTLEMENT

On May 15, 2018 ENMAX reached an agreement that resulted in a $12.5 million reduction to ENMAX's onerous provision.

GLOSSARY OF TERMS

AC	Audit Committee
ACFA	Alberta Capital Finance Authority
ACTA	Alberta Corporate Tax Act
AESO	Alberta Electric System Operator
Alberta Finance	Alberta Finance, Tax and Revenue Administration
AQMS	National Air Quality Management System
AUC	Alberta Utilities Commission
BLIERs	Base level industrial emissions Requirements
Board	ENMAX's Board of Directors
Corporation	ENMAX Corporation and its subsidiaries
CES	Calgary Electric System
CCEMA	Change and Emissions Management Amendment
CIAC	Contributions in aid of construction
CPA Handbook	Canadian Professional Accountants Handbook
CRMC	Commodity Risk Management Committee
CUPE	The Canadian Union of Public Employees
DAS	Distribution Access Services
DB	Defined benefit
DBO	Defined benefit obligation
DC	Defined contribution
Divisions	ENMAX Transmission and ENMAX Distribution
EBIT	Earnings before interest and income taxes
EBITDA	Earnings before interest, income tax and depreciation and amortization
EMS	Environmental management system
ENMAX	ENMAX Corporation and its subsidiaries
ERM	Enterprise risk management
EUA	Alberta Electric Utilities Act
FFO	Funds from operations
FVTPL	Fair value through profit or loss
FX	Foreign exchange
GHG	Greenhouse gas
GJ	Gigajoule
GWh	Gigawatt hour
IBEW	International Brotherhood of Electrical Workers
ICFR	Internal control over financial reporting
IFRS	International Financial Reporting Standard
ITA	Income Tax Act (Canada)
JVA	Joint venture agreement
LLR	Line Loss Rule
MD&A	Management's Discussion and Analysis
MSA	Market Surveillance Administrator
MW	Megawatt
MWh	Megawatt hour
NOx	Nitrogen oxide
OCI	Other comprehensive income
OM&A	Operations, maintenance and administration
PBR	Performance based regulation
PILOT	Payment in lieu of tax
PPA	Power purchase arrangement
PPE	Property, plant and equipment
RMC	Risk Management Committee
ROE	Return on equity
RRO	Calgary Regulated rate option
SaaS	Software as a service
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SGER	Specified Gas Emitters Regulation
Shepard	Shepard Energy Centre
SIPP	Statement of Investment Policies and Procedures
SO2	Sulphur dioxide
The City	The City of Calgary
WACC	Weighted average cost of capital
WPC	Wind Participation Consortium

ADDITIONAL INFORMATION

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

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