ENMAX CORPORATION

Q3 2019 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 November 20, 2019, is a review of the results of operations of ENMAX Corporation and its subsidiaries (the Corporation) for the three and nine months ended September 30, 2019, compared with 2018, and of the Corporation's financial condition and prospects. This MD&A should be read in conjunction with the Q3 2019 Condensed Consolidated Interim Financial Statements and the 2018 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.

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Glossary of terms can be found on page 44 of the Condensed Consolidated Interim Financial Statements.

MARKET CONDITIONS

Year to date 2019, market power prices and spark spreads are stronger than the prior period. The Alberta average power market pool price settled at $46.95 per megawatt hour (MWh) for the third quarter of 2019, which is 14 per cent lower than the same period in 2018 when the average was $54.46 per MWh. For the nine months ended September 30, 2019, average power market prices rose to $58.02 per MWh compared to $48.39 MWh in 2018. Market spark spreads settled at $40.57 for the third quarter of 2019 compared to $45.69 for the same period in 2018. Year to date, the market spark spread has improved to $47.02 compared to $37.73 in the prior period. ENMAX's hedging strategy secures significant margins before entering the year, offering protection from decreasing power prices while maintaining some ability to capitalize on price increases.

Alberta demand (load) averaged 9,363 MW in the third quarter of 2019, which is a 1.4 per cent decrease over the same quarter in 2018. The average for 2019 year to date is 9,633 MW, same as prior period. ENMAX's business model, which includes generating, moving and marketing electricity, generally benefits from demand growth through increases in generator revenue, retail sites, and distribution rate base. Items such as spark spreads and allowable recoveries on rate base will materially impact ENMAX's business model.

Alberta natural gas prices averaged $0.85 per gigajoule (GJ) for the third quarter in 2019, which is $0.32 lower compared to the average for the third quarter of 2018. Natural gas prices, while likely to be higher in Q4 due to seasonality, are expected to remain relatively weak in the near term as maintenance on the Nova Gas Transmission Ltd. system (NGTL) is expected to continue until 2023, restricting access to export markets and gas storage thereby increasing supply. Lower natural gas prices are generally positive for ENMAX's portfolio of natural gas-fuelled power plants; however, continued pipeline restrictions pose a gas delivery risk to ENMAX's assets, which could create financial and operational challenges. ENMAX manages this risk by optimizing our allocation of gas to our facilities and purchasing capacity from natural gas market participants.

Recent and anticipated regulatory announcements will impact the Alberta power market. The existing Carbon Competitiveness Incentive Regulation (CCIR) will apply to large emitters until December 31, 2019. January 1, 2020 CCIR is expected to be replaced with the Technology Innovation and Emissions Reductions (TIER) mechanism. The proposed carbon compliance cost under the proposed TIER is the same as CCIR. Previous announcement made by provincial and federal bodies are expected to shape the electricity industry starting in 2020. These announcements include a review of the electricity price cap, the federal government's imposition of the federal backstop carbon pricing mechanism, and Alberta's legal challenge of the federal carbon tax. The outcome of the federal election is not expected to have an immediate impact on the Alberta electric industry; however, the Liberal government has left the door open on federal carbon tax pricing increases post 2022.

The Alberta power market is also impacted by several market participants announcing updates to their project schedules, impacting supply post 2020. In the period 2021 to 2023, this includes intentions to cofire existing coal units, coal-to-gas conversions, as well as utility scale solar projects, along with new large cogeneration units in the second half of 2023. ENMAX is continuing to evaluate the potential impact of the various scenarios on its business and customers.

FINANCIAL PERFORMANCE

The table below presents ENMAX's adjusted earnings before interest, taxes, depreciation and amortization (Adjusted EBITDA), adjusted earnings before interest and taxes (Adjusted EBIT) and comparable net earnings. Management believes that a measure of operating performance is more meaningful if the impact of specific items is excluded from the financial information. As a result, these financial metrics exclude onerous provisions (recoveries) on long-term contracts, foreign exchange gains (losses), unrealized gains (losses) on commodities where settlement on derivatives will occur in a future period and Emera Maine acquisition-related costs (see Significant Events section). Refer to the Non-IFRS Financial Measures section on page 10 for definitions and further descriptions of the financial measures.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

	Three months ended September 30,		Nine months ended September 30,	
(millions of Canadian dollars)	**2019**	**2018**	**2019**	**2018**
Total revenue	**577.4**	608.1	**1,869.2**	1,760.9
Adjusted EBITDA [(1)(2)]				
Competitive Energy	**57.0**	46.8	**155.3**	146.5
Power Delivery	**64.0**	57.8	**182.8**	157.9
Corporate and Eliminations	**0.3**	15.4	**0.3**	3.6
Consolidated	**121.3**	120.0	**338.4**	308.0
Adjusted EBIT [(1)(2)]				
Competitive Energy	**25.8**	16.5	**62.1**	56.4
Power Delivery	**34.2**	31.5	**94.5**	78.0
Corporate and Eliminations	**1.3**	15.4	**3.3**	3.6
Consolidated	**61.3**	63.4	**159.9**	138.0
Comparable net earnings [(1)(2)(3)]	**40.7**	45.9	**116.7**	98.9
Net earnings (loss)	**42.5**	64.4	**141.4**	(23.8)
Free cash flow (FCF) [(1)(4)]			**96.1**	243.4
Capital expenditures	**99.1**	80.4	**291.1**	245.7

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

[(2)] Does not include:

- Realized and unrealized foreign exchange losses of $1.6 million and $1.6 million (2018 - $0.3 and $11.4 million gains) for the three and nine months ended September 30, 2019, respectively.
- Unrealized electricity and gas mark-to-market for the three and nine months ended September 30, 2019 of $52.9 million and $99.9 million gains (2018 - $25.7 and $28.5 million gains) respectively.
- Onerous provision of $nil (2018 - $nil and $12.5 million recovery) for the three and nine months ended September 30, 2019, respectively.
- Emera Maine acquisition related costs of $8.6 and $15.6 million (2018 – $nil) for the three and nine months ended September 30, 2019 respectively, including $1.2 million and $6.4 million, respectively, related to finance charges that are included in calculating Comparable net earnings.

[(3)] Does not include tax adjustments of $26.6 million and $26.6 million (2018 - $nil and $164.3 million expense) for the three and nine months ended September 30, 2019, respectively.

[(4)] FCF is calculated for the twelve months ended September 30, 2019 and 2018 respectively.

Total revenue for the three and nine months ended September 30, 2019 has decreased by $30.7 million and increased $108.3 million, respectively from the comparable period in 2018. The year to date growth is related to conditions in the Alberta electricity market (see Market Conditions section) that have increased the price we receive from our customers on products exposed to market prices, matching the cost exposure to ENMAX in providing the product. ENMAX has also seen revenue growth in our transmission and distribution segment related to favourable rulings.

ENMAX's Adjusted EBIT decreased by $2.1 million and increased $21.9 million for the three and nine months ended September 30, 2019 respectively, as compared with the three and nine months ended September 30, 2018. Overall in 2019, ENMAX has had strong, stable growth through its business segments by taking advantage of favourable market conditions, continued monitoring of regulatory environments and implementation of strategic initiatives to improve business performance. The primary drivers for the change in Adjusted EBIT were as follows:

- ENMAX Competitive Energy (Competitive Energy) – In the quarter, Competitive Energy had lower Adjusted EBIT compared to the prior year primarily due to lower emission offset sales combined with lower electricity margins as a result of decreased spark spreads. Year to date, Adjusted EBIT was higher compared to the prior year due to capturing higher spark spreads in the first half of 2019. Competitive Energy was able to realize higher natural gas margins due to increased sales to customers. Operational costs in 2019 were higher due to staffing cost increases across the business, year over year increased technology support costs, and increased allowance for uncollectable receivables as a result of prevailing economic conditions in Alberta.
- ENMAX Power Delivery (Power Delivery) – The regulated business continues to grow largely a result of the Calgary service area's need to replace its aging infrastructure and continued growth. The increase in Power Delivery's Adjusted EBIT over 2018 resulted from the approval by the Alberta Utilities Commission (AUC) of the 2019 Distribution rates in addition to cost reductions as a result of strategic restructuring.
- ENMAX Corporate and Eliminations (Corporate and Eliminations) – This segment experienced lower adjusted EBIT for the three and nine months ended September 30, 2019 compared to the comparative periods. This change is primarily the result of staffing changes in 2019 that increased costs for Corporate and Eliminations. This is offset by organizational process changes that were prospectively applied in the third quarter of 2018. These changes have no impact on the consolidated results of the Corporation.

ENMAX's net earnings decreased by $21.9 million for the three months and increased $165.2 million for the nine months ended September 30, 2019 as compared to the same periods in 2018. A one-time tax adjustment was recorded during the first quarter of 2018 as a result of the Alberta Court of Appeal decision (see Income Tax section for further details).

As at September 30, 2019, ENMAX's balance sheet continued to show strength as the Corporation carefully manages debt to cash flow ratios as well as capital investment. ENMAX's prudent balance sheet management has enabled the Corporation to continue to achieve growth and profitability in the uncertain economic environment.

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.

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

SIGNIFICANT EVENTS

EMERA MAINE ACQUISITION

On March 25, 2019, the Corporation announced that it had entered into a definitive agreement to acquire Emera Maine, a regulated electric transmission and distribution company in Maine, for a purchase price of $1,286 million. Including assumed debt, the aggregate enterprise value is expected to be approximately $1,800 million. This transaction is aligned with the corporate strategy to grow regulated cash flows and diversify revenue streams within North America. The acquisition will raise ENMAX's regulated rate base by approximately 50 per cent and increase the portion of future cash flows from regulated and non-commodity sources to approximately 70 per cent. ENMAX intends to fund this transaction through a combination of cash, a two-year bank loan, which is intended to be repaid before maturity, and private notes (see Liquidity section).

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 subsequently filed an application with the Supreme Court of Canada seeking leave to appeal. On February 28, 2019 the Supreme Court of Canada dismissed the application (see Income Tax section).

ENMAX COMPETITIVE ENERGY BUSINESS AND UPDATE

Competitive Energy is an integrated business providing customers with electricity, natural gas, distributed energy resource solutions, and engineering, procurement and construction services. Our competitive advantage is our ability to hedge our low-cost generation assets through our retail business, the largest in Alberta by number of customers and energy consumed. The competitive retail business provides customers with fixed-price electricity linked to our wind and gas-fuelled generation assets, and provides opportunities to offer additional energy services, such as solar installations and thermal energy. As at September 30, 2019, Competitive Energy's capacity ownership interest was 1,509 MW of electricity generation: 1,289 MW from natural gas-fuelled plants, 217 MW from wind power and 3 MW from combined heat and power (CHP) generation.

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 into the Alberta market.

KEY BUSINESS STATISTICS

	Three months ended September 30,		Nine months ended September 30,	
	2019	**2018**	**2019**	**2018**
Plant availability (%) [1]	**99.19**	99.30	**95.41**	91.70
Average flat pool price ($/MWh)	**46.95**	54.46	**58.02**	48.39
Spark spread ($) [2]	**40.57**	45.69	**47.02**	37.73

(1) Plant availability (%) reflects planned maintenance and forced outages.
(2) Based on market prices.

For the three months ended September 30, 2019 our plant availability was 99.19 per cent; this high availability allows the assets to perform as planned in our hedge path and seek further opportunities in supplying the market. For the year to date, plant availability was higher than the prior period due to planned outage events in 2018 at the Shepard Energy Centre and Calgary Energy Centre. For the nine months ended September 30, 2019 our plant availability was 95.41%, reflecting unplanned outages in the second quarter of 2019. Unplanned outages impact our operations as we need to source electricity from the open market, exposing our costs of supplying power to our Retail customer at prevailing market prices.

For the three months ended September 30, 2019 the average flat pool power price decreased relative to the comparative period. This was primarily due to lower demand caused by cooler temperatures. During the first nine months of 2019, the average flat pool power price increased from 2018 levels. This was primarily due to the extreme temperatures Alberta experienced during February 2019 which increased demand in a tightened supply market combined with various industry participant plant outages throughout Alberta during the second quarter.

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-fuelled power plant from generating an unhedged unit of electricity. For the three months ended September 30, 2019, the decrease from the comparative period is due to lower than average flat pool prices (as described above). With respect to the nine months ended September 30, 2019, the market improvement from 2018 levels was driven by higher average flat pool prices (as described above) as the change in the price of natural gas had a minimal impact on the spark spread.

In the retail business our fixed price electricity volumes increased over prior year in both the three and nine month ended September 30, 2019, improving our ability to hedge our generation assets. Offsetting the volume improvement, our competitive products were impacted by higher cost of goods sold combined with the impact of Bill 16 (An Act to Cap Regulated Electricity Rates, implemented June 1, 2017).

Electricity margins (see section ENMAX Financial Results) are slightly less than prior year in the quarter due to impact of lower third quarter spark spreads on open positions compared to the prior period. For the nine months ended September 30, 2019 our electricity margins improved period over period due to increase year to date market power and spark spreads over prior year, offsetting the impact of unplanned asset outages in the second quarter. Our risk mitigation strategies, which resulted in the contracting of most of our market position, continue to deliver the majority of our margin with less exposure to the volatility of near-term spark spreads.

ENMAX manages its 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. However, due to our hedging and contracting strategies, the impact of in-year price movements is tempered given our strategy to deliver predictable cash flows over time.

ENMAX POWER DELIVERY BUSINESS AND UPDATE

Power Delivery's highest priorities are providing safe, reliable and efficient delivery of electricity to 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 AUC to request approval for 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 September 10, 2019, Power Delivery filed its 2020 Annual Performance Based Regulation (PBR) Distribution Interim Rate Application for the period of January 1, 2020 to December 31, 2020, which included a rate increase of 3.3 per cent for 2020.
- On February 12, 2019, the AUC approved the 2019 Interim Transmission Tariff Application of $89.9 million, effective May 1, 2019, which resulted in $8.7 million higher revenue than the 2017 interim Transmission tariff that was in place prior to this decision.
- On December 21, 2018, the AUC issued a decision approving 2019 PBR distribution rates on an interim basis and distribution tariff terms and conditions for the period of January 1, 2019 to December 31, 2019, which resulted in approximately $1.0 million of additional 2019 revenue due to a rate adjustment of 2.7 per cent.
- On December 12, 2018, the 2018-2020 Transmission General Tariff Application was filed with the AUC requesting final approval of forecast revenue requirements of $85.7 million, $95.7 million, and $106.4 million in 2018, 2019 and 2020, respectively. The application is currently ongoing.

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

KEY BUSINESS STATISTICS

	Three months ended September 30,		Nine months ended September 30,	
	2019	**2018**	**2019**	**2018**
Distribution volumes in Gigawatt Hours (GWh)	**2,272**	2,382	**6,947**	7,097
System average interruption duration index (SAIDI) [1]	**0.16**	0.18	**0.33**	0.48
System average interruption frequency index (SAIFI) [2]	**0.27**	0.25	**0.59**	0.75

[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 to date in 2019 decreased 5 and 2 per cent for the three and nine months ended September 30, 2019, respectively. This slightly lower volume is due to lower customer usage from a combination of milder summer weather, weaker economic conditions and energy efficiency in 2019. Partially offsetting this decrease are increased sites mainly from residential homes in 2019 compared to the 2018 comparative periods.

When compared to the year to date performance of other Canadian Electricity Association member utilities, ENMAX has remained one of the most reliable transmission and distribution utilities in Canada. Both SAIDI and SAIFI are moderately favourable year to date compared to the same period in 2018, due to lower pole fires and equipment failures. ENMAX continues to monitor the cause of any outages to mitigate future occurrences.

ENMAX FINANCIAL RESULTS

ADJUSTED EARNINGS BEFORE INTEREST AND INCOME TAXES (ADJUSTED EBIT) COMPARED WITH THE SAME PERIOD IN 2018

For the three months ended September 30, *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate**	**Consolidated**
Adjusted EBIT [1] for the period ended September 30, 2018	16.5	31.5	15.4	63.4
Increased (decreased) margins attributable to:				
Electricity	(2.3)	-	-	(2.3)
Natural gas	(0.3)	-	(0.2)	(0.5)
Transmission and distribution	-	2.3	-	2.3
Contractual services and other	5.5	0.5	(9.2)	(3.2)
Decreased (increased) expenses:				
Operations, maintenance & administration (OM&A) [2]	7.3	3.4	(5.7)	5.0
Depreciation and amortization	(0.9)	(3.5)	1.0	(3.4)
Adjusted EBIT [1] for the period ended September 30, 2019	25.8	34.2	1.3	61.3

(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 nine months ended September 30, *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate**	**Consolidated**
Adjusted EBIT [1] for the period ended September 30, 2018	56.4	78.0	3.6	138.0
Increased (decreased) margins attributable to:				
Electricity	9.0	-	(0.4)	8.6
Natural gas	0.6	-	(0.1)	0.5
Transmission and distribution	-	14.6	-	14.6
Contractual services and other	(1.8)	(0.3)	0.6	(1.5)
Decreased (increased) expenses:				
Operations, maintenance & administration (OM&A) [2]	1.0	10.6	(3.4)	8.2
Depreciation and amortization	(3.1)	(8.4)	3.0	(8.5)
Adjusted EBIT [1] for the period ended September 30, 2019	62.1	94.5	3.3	159.9

(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.

Electricity margins for the three months ended September 30, 2019 decreased $2.3 million or 3 per cent compared to the same period in 2018, primarily due to the impact of lower spark spreads on our uncontracted positions. With respect to the nine months ended September 30, 2019, electricity margins increased $8.6 million or 4 per cent compared to the same period in 2018. The favourable variance is due to the positive impact of spark spreads on our uncontracted positions.

Natural gas margins for the three months ended September 30, 2019 decreased $0.5 million or 6 per cent compared to the same period in 2018, primarily due to lower retail consumption volumes. For the nine months ended September 30, 2019, natural gas margins increased $0.5 million or 1 per cent compared to the same period in 2018. The increase was primarily due to higher retail consumption volumes as a result of increased site acquisitions.

For the three and nine months ended September 30, 2019, transmission and distribution margins increased $2.3 million or 3 per cent and $14.6 million or 6 percent compared to the same periods in 2018, respectively. The favourable variance is mainly due to increased Distribution revenue as a result of the approval of the 2019 Distribution rates.

Contractual services and other margins for the three and nine months ended September 30, 2019 decreased by $3.2 million or 11 per cent, and $1.5 million or 2 per cent, respectively, compared to the prior year primarily due to lower emission offset sales.

OM&A for the three and nine months ended September 30, 2019 decreased $5.0 million or 6 per cent, and decreased $8.2 million or 3 per cent, when compared to the same period in 2018. The favourable variance is the result of decreased salary costs as a result of strategic restructuring at the end of 2018.

During the three and nine months ended September 30, 2019, the Corporation recorded $9.8 million and $22.0 million in Emera Maine acquisition related costs, of which $1.2 and $6.4 million are related to finance charges. These costs are not included in adjusted EBIT.

Depreciation and amortization expense increased $3.4 million or 6 per cent and increased $8.5 million or 5 per cent when compared to the same periods in 2018. The increase was consistent with capital asset additions in in the period.

OTHER NET EARNINGS ITEMS

Finance charges for the three and nine months ended September 30, 2019 increased $1.7 million or 10 per cent and increased $6.3 million or 12 per cent compared to the same periods in 2018 respectively. The increase was primarily driven by additional financing costs related to the Emera Maine acquisition.

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 and nine months ended September 30, 2019, 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 various tax disputes.

For the three and nine months ended September 30, 2019, the Corporation recorded tax expense of $42.9 million and $42.8 million (2018 – $7.5 and $162.1 million expense), respectively. The change in income tax is primarily due to the impact of the Alberta Court of Appeal decision in the first quarter of 2018.

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 revenues and expenses, as well as re-measurement gains and losses on pension retirement benefits.

For the three and nine months ended September 30, 2019, OCI had total gains of $3.3 and $23.6 million respectively, compared with losses of $35.1 million and $7.4 million respectively, for the same periods in 2018. The OCI gains primarily reflect the favourable fair value changes in electricity and commodity positions and hedged instruments. This is partially offset by the reclassification of gains on derivative instruments to net earnings.

Accumulated other comprehensive income (loss) is reflected in shareholder's equity along with retained earnings and share capital. Retained earnings for the period increased $113.4 million as a result of net earnings recognized in 2019, partially offset by dividends on common shares.

NON-IFRS FINANCIAL MEASURES

The Corporation uses Adjusted EBITDA, 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 and exclude onerous provisions (recoveries) on long-term contracts, foreign exchange gains (losses), unrealized gains (losses) on commodities where settlement on derivatives will occur in a future period and Emera Maine acquisition-related costs.

ADJUSTED EBITDA

	Three months ended September 30,		Nine months ended September 30,	
(millions of Canadian dollars)	**2019**	**2018**	**2019**	**2018**
Net earnings (loss) (IFRS financial measure)	**42.5**	64.4	**141.4**	(23.8)
Add (deduct):				
Unrealized (gains) on commodities	**(52.9)**	(25.7)	**(99.9)**	(28.5)
Foreign exchange losses (gains)	**1.6**	0.3	**1.6**	(11.4)
Total costs related to the acquisition of Emera Maine [1]	**9.8**	-	**22.0**	-
Onerous provision (recovery)	**-**	-	**-**	(12.5)
Net income tax expense on unrealized (gains) on commodities, and foreign exchange losses (gains)	**13.1**	6.9	**25.0**	10.8
Tax adjustments	**26.6**	-	**26.6**	164.3
Comparable net earnings (non-IFRS financial measure)	**40.7**	45.9	**116.7**	98.9
Add (deduct):				
Depreciation and amortization	**60.0**	56.6	**178.5**	170.0
Remaining finance charges	**17.4**	16.9	**52.0**	52.1
Remaining income tax (recovery) expense	**3.2**	0.6	**(8.8)**	(13.0)
Adjusted EBITDA (non-IFRS financial measure)	**121.3**	120.0	**338.4**	308.0

[1] Includes finance charges related to the acquisition of Emera Maine.

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

Adjusted EBITDA excludes the impact of unrealized (gains) on commodities, foreign exchange losses (gains), Emera Maine acquisition related costs, and onerous provisions (recovery) from the adjusted operating profit. Management believes that a measure of operating performance is more meaningful if results not related to normal operations, such as onerous provisions on long-term contracts, foreign exchange (gains) losses, and unrealized (gains) losses on commodities 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 Canadian dollars)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Net earnings (loss) (IFRS financial measure)	**42.5**	64.4	**141.4**	(23.8)
Add (deduct):				
Unrealized (gains) on commodities	**(52.9)**	(25.7)	**(99.9)**	(28.5)
Foreign exchange losses (gains)	**1.6**	0.3	**1.6**	(11.4)
Finance charges [1]	**24.4**	16.9	**52.0**	52.1
Total costs related to the acquisition of Emera Maine [2]	**2.8**	-	**22.0**	-
Onerous provision (recovery)	**-**	-	**-**	(12.5)
Income tax (recovery) expense	**42.9**	7.5	**42.8**	162.1
Adjusted EBIT (non-IFRS financial measure)	**61.3**	63.4	**159.9**	138.0

(1) Excludes finance charges related to the acquisition of Emera Maine.

(2) Includes finance charges related to the acquisition of Emera Maine.

The Corporation focuses on Adjusted EBIT, which excludes the impact of foreign exchange (gains) losses, unrealized (gains) losses on commodities, Emera Maine acquisition related costs, and (recoveries) of onerous provisions. 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 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 funded from operations. Management believes that FCF provides useful information to show liquidity after accounting for capital required to maintain and grow the business over a twelve-month cycle.

For the twelve months ended September 30, *(millions of Canadian dollars)*	2019	2018
Net cash provided by operating activities [1]	**333.1**	394.9
Capital expenditures funded from operations [2]	**(237.0)**	(151.5)
Free cash flow (non-IFRS financial measure)	**96.1**	243.4

(1) Refer to Liquidity and Capital Resources section.

(2) Includes cash provided to fund capital expenditures in Power Delivery that would otherwise be considered financing activities.

ENMAX's FCF decreased $147.3 million for the twelve-months ended September 30, 2019, as compared with the twelve-months ended September 30, 2018. In the current period, a greater portion of capital expenditures were funded using cash from operations than the twelve months ending September 30, 2018.

FINANCIAL CONDITION

SIGNIFICANT CHANGES IN THE CORPORATION'S FINANCIAL CONDITION

As at *(millions of Canadian dollars, except % change)*	**September 30, 2019**	**December 31, 2018**	**$ Change**	**% Change**	**Explanation for Change**
ASSETS					
Cash and cash equivalents	**122.2**	89.0	33.2	37%	Refer to Liquidity section.
Accounts receivable	**621.8**	711.6	(89.8)	(13%)	Decrease is mainly attributable to the timing of receipts and seasonal fluctuation in revenue.
Income tax receivable	**8.3**	45.6	(37.3)	(82%)	Decrease is primarily due to recognition of tax settlement.
Deferred income tax assets	**21.0**	52.2	(31.2)	(60%)	Decrease is primarily due to recognition of tax settlement.
Other assets [1]	**70.7**	109.1	(38.4)	(35%)	Decrease is mainly due to lower restricted cash on potential margin calls.
LIABILITIES AND SHAREHOLDER'S EQUITY					
Short-term financing	**-**	18.0	(18.0)	(100%)	Refer to Liquidity section.
Accounts payable	**418.3**	624.6	(206.3)	(33%)	Decrease mainly attributable to timing of disbursements.
Dividend payable	**12.5**	-	12.5	100%	Dividend declared in March to be paid in quarterly payments over the course of 2019.
Deferred income tax liabilities	**32.6**	57.3	(24.7)	(43%)	Decrease is primarily due to recognition of tax settlement.
Financial liabilities [1]	**26.0**	155.4	(129.4)	(83%)	Change in fair value of hedged and non-hedged derivatives.
Lease liabilities [1]	**60.1**	4.2	55.9	1331%	Increase is due to prospective adoption of IFRS 16.
Asset retirement obligations and provisions [1]	**139.2**	107.7	31.5	29%	Increase is mainly attributable to the change in discount rates.

[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. 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 long-term debt.

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 September 30, 2019, the Corporation was in compliance with all debt covenants and expects to continue to comply with such covenants.

ENMAX's total debt balance at September 30, 2019 was $1,806.6 million (December 31, 2018 - $1,703.9 million) of which $nil (December 31, 2018 - $18.0 million) is in commercial paper. During the second quarter of 2019, ENMAX acquired $172.4 million of debentures from the City of Calgary through arrangements with the Alberta Capital Finance Authority (ACFA) with an average rate of 2.65 per cent with maturities ranging from 2024 to 2044.

As at September 30, 2019, ENMAX had access to approximately $2,622.0 million (December 31, 2018 - $850.0 million) in credit facilities, of which $302.2 million (December 31, 2018 - $376.4 million) has been drawn upon. The additional facilities in the current year were made available to facilitate the Emera Maine transaction. These will be cancelled as needed around acquisition close. The Corporation's credit facilities mature between 2020 and 2022 and are provided by national and regional lenders.

On October 3, 2019, S&P Global provided an update on their rating for ENMAX, reducing the Corporation's credit rating to BBB and placing the ratings on CreditWatch with negative implications. The update was in response to ENMAX's plans to issue private debentures to partially fund the proposed acquisition of Emera Maine (see Significant Events section). DBRS continues to maintain ENMAX's current credit rating of A(low) and has placed the company under review – negative, citing an increase in financial risk due to the associated additional debt.

On October 15, 2019, the Corporation issued $850 million in unsecured private debentures with a weighted average interest rate of 3.35 per cent with maturities ranging from 2022 to 2029. The debentures have special mandatory redemption rights and will be held in escrow until the acquisition is complete. ENMAX intends to use FCF to maximize deleveraging over the next two or three years following closing of the deal.

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 conducted its 2006 audit of ENMAX Energy Corporation and ENMAX PSA Corporation, it disagreed with the interest expense deducted on the payment in lieu of tax (PILOT) returns. ENMAX Corporation entered into intercompany loans with its affiliates ENMAX Energy Corporation in 2004 and ENMAX PSA Corporation in 2006 and 2007. ENMAX has received reassessments and communications from Alberta Finance in respect of the taxation years from 2004 through 2013. This matter was heard before the Court of Queen's Bench of Alberta with a decision rendered in favour of ENMAX on June 17, 2016. Following this decision, the Crown appealed, and the appeal was heard by the Court of Appeal of Alberta on October 12, 2017. 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. On February 28, 2019 the Supreme Court of Canada dismissed the application.

On June 28, 2019, The Alberta Bill 3 Job Creation Tax Cut (Alberta Corporate Tax Amendment) Act ("Bill 3") received Royal Assent and came into force. This newly enacted legislation is set to decrease the provincial corporate tax rate from 12 per cent to 11 per cent on July 1, 2019, with further 1 per cent rate reductions every year on January 1 until the general corporate tax rate reaches 8 per cent on January 1, 2022. This multi-year phased-in tax reduction is considered enacted for tax reporting purposes for the second quarter of 2019 and is therefore required to be reflected in the Q3 2019 Condensed Consolidated Interim Financial Statements.

COMBINED STATUTORY TAX RATE (FEDERAL AND ALBERTA)

2019 [1]	26.5%
2020	25.0%
2021	24.0%
2022	23.0%

[1] Prorated statutory tax rate for 2019 taxation year based on ENMAX's December 31 year end.

RISK MANAGEMENT AND UNCERTAINTIES

There have been no material changes in the nine months ended September 30, 2019 to the Corporation's business and operational risks as described in the Corporation's December 31, 2018 MD&A.

CONSOLIDATED FINANCIAL STATEMENTS

Contents

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

As at *(unaudited)* *(millions of Canadian dollars)*		**September 30, 2019**		**December 31, 2018**
ASSETS				
Cash and cash equivalents	**$**	**122.2**	$	89.0
Accounts receivable		**621.8**		711.6
Income taxes receivable		**8.3**		45.6
Current portion of financial assets (Note 6)		**99.9**		58.3
Other current assets (Note 10)		**88.2**		118.9
		940.4		1,023.4
Property, plant and equipment (Notes 4 and 8)		**4,423.3**		4,253.9
Intangible assets		**177.4**		177.8
Deferred income tax assets (Note 11)		**21.0**		52.2
Financial assets (Note 6)		**42.4**		29.9
Other long-term assets (Note 10)		**31.9**		27.1
TOTAL ASSETS		**5,636.4**		5,564.3
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES (Note 7)		**37.3**		82.0
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	**$**	**5,673.7**	$	5,646.3
LIABILITIES				
Short-term financing (Note 6)	**$**	**-**	$	18.0
Accounts payable and accrued liabilities		**418.3**		624.6
Income taxes payable (Note 11)		**0.1**		0.1
Dividend payable (Note 14)		**12.5**		-
Current portion of long-term debt (Notes 6)		**74.6**		71.3
Current portion of financial liabilities (Note 6)		**88.5**		108.4
Current portion of deferred revenue (Note 9)		**6.9**		7.2
Current portion of lease liabilities (Notes 4 and 8)		**5.0**		0.1
Other current liabilities (Note 10)		**37.5**		24.8
Current portion of asset retirement obligations and other provisions		**0.9**		1.7
		644.3		856.2
Long-term debt (Notes 6)		**1,732.0**		1,614.6
Deferred income tax liabilities (Note 11)		**32.6**		57.3
Post-employment benefits		**52.6**		51.1
Financial liabilities (Note 6)		**79.8**		135.2
Deferred revenue (Note 9)		**549.4**		543.4
Lease liabilities (Notes 4 and 8)		**55.1**		4.1
Other long-term liabilities (Note 10)		**11.9**		12.1
Asset retirement obligations and other provisions		**138.3**		106.0
TOTAL LIABILITIES		**3,296.0**		3,380.0
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES (Note 7)		**1.4**		5.0
SHAREHOLDER'S EQUITY				
Share capital		**280.1**		280.1
Retained earnings		**2,077.3**		1,985.9
Accumulated other comprehensive income (loss) (Note 12)		**18.9**		(4.7)
		2,376.3		2,261.3
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY	**$**	**5,673.7**	$	5,646.3

Commitments and contingencies (Note 17)
See accompanying Notes to Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF EARNINGS (LOSS)

(unaudited) *(millions of Canadian dollars)*	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
REVENUE (Note 5)				
Electricity	**$ 294.5**	$ 329.6	**$ 951.3**	$ 919.4
Natural gas	**15.0**	17.8	**130.3**	116.9
Transmission and distribution	**186.8**	173.5	**559.4**	493.6
Local access fees	**37.4**	39.7	**105.7**	103.3
Contractual services	**29.3**	32.6	**92.0**	97.7
Contributions in aid of construction (CIAC) revenue (Note 9)	**4.7**	4.4	**14.1**	13.1
Other income (Note 13)	**9.7**	10.5	**16.4**	16.9
TOTAL REVENUE	**577.4**	608.1	**1,869.2**	1,760.9
OPERATING EXPENSES (Note 5)				
Electricity and fuel purchases	**153.1**	211.4	**600.3**	646.5
Natural gas and delivery	**6.5**	8.8	**89.7**	76.8
Transmission and distribution	**88.6**	94.8	**272.9**	278.3
Local access fees	**37.4**	39.7	**105.7**	103.3
Depreciation and amortization	**59.9**	56.6	**177.0**	170.0
Other expenses (Note 13)	**112.7**	109.1	**339.9**	313.3
TOTAL OPERATING EXPENSES	**458.2**	520.4	**1,585.5**	1,588.2
OPERATING PROFIT	**119.2**	87.7	**283.7**	172.7
Finance charges	**18.6**	16.9	**58.4**	52.1
NET EARNINGS BEFORE TAX	**100.6**	70.8	**225.3**	120.6
Current income tax expense (Note 11)	**26.6**	1.3	**26.7**	134.9
Deferred income tax expense (Note 11)	**16.3**	6.2	**16.1**	27.2
NET EARNINGS (LOSS) - BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES	**57.7**	63.3	**182.5**	(41.5)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES (Note 7)	**(15.2)**	1.1	**(41.1)**	17.7
NET EARNINGS (LOSS)	**$ 42.5**	$ 64.4	**$ 141.4**	$ (23.8)

See accompanying Notes to the Condensed Consolidated Interim Financial Statements.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(unaudited) *(millions of Canadian dollars)*	**Three months ended September 30,**		**Nine months ended September 30,**	
	2019	**2018**	**2019**	**2018**
NET EARNINGS (LOSS)	**$ 42.5**	$ 64.4	**$ 141.4**	$ (23.8)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX				
Items that will not be reclassified subsequently to statement of earnings				
Remeasurement (losses) on retirement benefits [1]	**-**	-	**(0.2)**	-
Items that will be reclassified subsequently to statement of earnings				
Unrealized gains on derivative instruments [2]	**9.4**	(27.5)	**34.6**	(2.8)
Reclassification of (gains) on derivative instruments to net earnings [3]	**(6.1)**	(7.6)	**(10.8)**	(4.6)
Other comprehensive income (loss), net of income tax	**3.3**	(35.1)	**23.6**	(7.4)
TOTAL COMPREHENSIVE INCOME (LOSS)	**$ 45.8**	$ 29.3	**$ 165.0**	$ (31.2)

(1) Net deferred income tax of $nil for the three months ended September 30, 2019 (2018 - $nil), and $0.2 million income tax expense for the nine months ended September 30, 2019 (2018 - $nil)

(2) Net deferred income tax recovery of $1.3 million for the three months ended September 30, 2019 (2018 - $10.2 million tax recovery), and $10.3 million income tax expense for the nine months ended September 30, 2019 (2018 - $1.1 million tax recovery)

(3) Net deferred income tax expense of $2.5 million for the three months ended September 30, 2019 (2018 - $3.1 million tax expense), and $4.8 million income tax expense for the nine months ended September 30, 2019 (2018 - $2.9 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, 2019	$ 280.1	$ 1,985.9	$ (4.7)	$ 2,261.3
Net earnings	-	98.9	-	98.9
Other comprehensive income, net of income tax	-	-	20.3	20.3
Dividends (Note 14)	-	(50.0)	-	(50.0)
As at June 30, 2019	280.1	2,034.8	15.6	2,330.5
Net earnings	-	42.5	-	42.5
Other comprehensive income, net of income tax	-	-	3.3	3.3
As at September 30, 2019	**$ 280.1**	**$ 2,077.3**	**$ 18.9**	**$ 2,376.3**
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	-	(1.4)	-	(1.4)
As at January 1, 2018, as restated	280.1	2,020.8	11.7	2,312.6
Net loss	-	(23.8)	-	(23.8)
Other comprehensive (loss), net of income tax	-	-	(7.4)	(7.4)
Dividends (Note 14)	-	(40.0)	-	(40.0)
As at September 30, 2018	280.1	1,957.0	4.3	2,241.4
Net earnings	-	28.9	-	28.9
Other comprehensive (loss), net of income tax	-	-	(9.0)	(9.0)
As at December 31, 2018	**$ 280.1**	**$ 1,985.9**	**$ (4.7)**	**$ 2,261.3**

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 September 30, 2019	2018	Nine months ended September 30, 2019	2018
CASH (USED IN) PROVIDED BY:				
OPERATING ACTIVITIES				
Net earnings (loss)	**$ 42.5**	$ 64.4	**$ 141.4**	$ (23.8)
Items not involving cash:				
CIAC	**9.2**	16.7	**19.8**	34.9
CIAC revenue (Note 9)	**(4.7)**	(4.4)	**(14.1)**	(13.1)
Depreciation and amortization	**59.9**	56.6	**177.0**	170.0
Finance charges	**18.6**	16.9	**58.4**	52.1
Income tax expense (Note 11)	**38.5**	7.5	**38.3**	162.1
Change in unrealized market value of financial contracts (Note 6)	**(50.9)**	(25.9)	**(100.0)**	(31.4)
Post-employment benefits	**0.1**	1.2	**0.3**	1.4
Change in non-cash working capital (Note 15)	**31.0**	69.4	**(14.2)**	109.0
Cash flow from operations	**144.2**	202.4	**306.9**	461.2
Interest paid [1]	**(7.2)**	(1.6)	**(43.4)**	(34.0)
Income taxes paid	**-**	0.5	**(0.3)**	(2.1)
Net cash flow provided by operating activities	**137.0**	201.3	**263.2**	425.1
INVESTING ACTIVITIES				
Purchase of property, plant and equipment and intangibles [1]	**(99.1)**	(80.4)	**(291.1)**	(245.7)
Cash flow used in investing activities	**(99.1)**	(80.4)	**(291.1)**	(245.7)
FINANCING ACTIVITIES				
Repayment of short-term debt	**-**	-	**(375.8)**	(882.4)
Proceeds from short-term debt	**-**	-	**357.8**	674.6
Repayment of long-term debt	**(14.0)**	(6.6)	**(51.9)**	(343.3)
Proceeds from long-term debt	**-**	-	**172.4**	478.8
Repayment of lease liability	**(1.4)**	-	**(3.9)**	-
Dividend paid (Note 14)	**(12.5)**	(10.0)	**(37.5)**	(30.0)
Cash flow provided by (used in) financing activities	**(27.9)**	(16.6)	**61.1**	(102.3)
Increase in cash and cash equivalents	**10.0**	104.3	**33.2**	77.1
Cash and cash equivalents, beginning of period	**112.2**	54.0	**89.0**	81.2
CASH AND CASH EQUIVALENTS, END OF PERIOD [2]	**$ 122.2**	$ 158.3	**$ 122.2**	$ 158.3
Cash and cash equivalents consist of:				
Cash	**122.2**	158.3	**122.2**	158.3

[1] Total interest paid during the three and nine months ended September 30, 2019 was $8.9 million and $48.3 million, respectively (2018 - $2.3 and $38.1 million). Purchase of PPE and intangibles includes $2.1 and $4.9 million of capitalized borrowing costs in the three and nine months ended September 30, 2019, respectively (2018 - $1.4 and $4.1 million).

[2] Cash and cash equivalents include restricted cash of $8.1 million (December 31, 2018 - $12.4 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 Condensed Consolidated Interim Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED INTERIM FINANCIAL STATEMENTS
(unaudited)

1. DESCRIPTION OF THE BUSINESS

ENMAX Corporation (ENMAX or the Corporation), a wholly-owned subsidiary of the City of Calgary (the City), was incorporated under the *Business Corporations Act* (Alberta) in July 1997 to carry on the electric utility transmission and distribution operations previously carried on by the Calgary Electric System (CES), a former department of the City. Operations of the Corporation began on January 1, 1998, with the transfer of substantially all 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 interim financial statements do not include all disclosures required for the preparation of audited annual financial statements. Accordingly, these unaudited condensed interim consolidated financial statements should be read in conjunction with the 2018 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 November 20, 2019.

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 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 and estimates for the period starting January 1, 2019, reflecting the implementation of the new accounting standard in Note 4:

SIGNIFICANT ACCOUNTING JUDGMENTS

Financial Statement Area	Judgment Area
Leases	Identifying whether a contract contains a lease
	Determining whether it is reasonably certain extension or termination option(s) will be exercised
	Determination of whether variable payments are in-substance fixed

SIGNIFICANT ACCOUNTING ESTIMATES

Financial Statement Area	Estimate Area
Leases	Estimation of the term of the lease
	Selection of the appropriate discount rate applied to lease payments
	Assessment of whether a right-of-use asset is impaired

4. ADOPTION OF NEW ACCOUNTING STANDARDS

ENMAX has adopted the following new accounting standard for the first time for the financial year beginning on January 1, 2019.

IFRS 16, *Leases*

IFRS 16 introduces new or amended requirements with respect to lease accounting. It introduces significant changes to lessee accounting by removing the distinction between operating and finance leases requiring the recognition of a right-of-use asset and a lease liability at commencement for all leases, except for short-term leases (leases with a term of less than 12 months) and leases of low-value assets. In contrast to lessee accounting, the requirements for lessor accounting have remained largely unchanged. The impact of the adoption of IFRS 16 on ENMAX's unaudited condensed consolidated interim financial statements is described below and in Note 8.

ENMAX has adopted IFRS 16 as an adjustment to opening balances on January 1, 2019. There was no impact to opening retained earnings on adoption.

In the initial recognition calculation of lease liabilities ENMAX used a weighted average rate of 3.8 per cent to determine the net present value of future lease payments. As at December 31, 2018 $69.5 million was included in the commitment and contingency note related to future lease payments that have now been included in the initial finance lease obligations. ENMAX has recognized $57.8 million of lease liabilities on initial application of IFRS 16 on January 1, 2019.

(millions of Canadian dollars)	**As at January 1, 2019**
Operating lease commitment as at December 31, 2018	**69.5**
Present value impact	**(20.5)**
Discounted using the incremental borrowing rate at January 1, 2019	**49.0**
Extension and termination options reasonably certain to be exercised	**8.8**
Lease liabilities on adoption of IFRS 16	**57.8**
Lease liabilities recognized as at December 31, 2018	**4.2**
Lease liabilities as at January 1, 2019	**62.0**

Impact of the new definition of a lease

IFRS 16 determines whether a contract contains a lease on the basis of whether the customer has the right to control the use of an identified asset for a period of time in exchange for consideration.

ENMAX applies the definition of a lease and related guidance set out in IFRS 16 to all lease contracts entered or modified on or after January 1, 2019. In preparation for the initial application of IFRS 16, ENMAX has carried out an implementation project. The project has shown that the new definition in IFRS 16 will not significantly change the scope of contracts that meet the definition of a lease.

Impact on lease accounting

IFRS 16 changes how ENMAX accounts for leases previously classified as operating leases under IAS 17 and International Financial Reporting Interpretations Committee (IFRIC) 4.

ENMAX accounts for leases as follows:

a. Recognizes right-of-use assets and lease liabilities in the condensed consolidated interim financial statement of position, initially measured at the present value of future lease payment;

b. Recognizes depreciation of right-of-use assets and interest on lease liabilities in the condensed consolidated interim statement of earnings; and

c. Separates the total amount of cash paid into a principal portion and interest in the condensed consolidated interim statement of earnings.

Lease incentives are recognized as part of the measurement of the right-of-use assets and lease liabilities whereas under IAS 17 they resulted in the recognition of a lease incentive, amortized as a reduction of rental expense on a straight-line basis.

Under IFRS 16, right-of-use assets are tested for impairment in accordance with IAS 36 *Impairment of Assets*. This replaces the previous requirement to recognize a provision for onerous lease contracts.

ELECTED PRACTICAL EXPEDIENTS

Single discount rate

To apply a single discount rate to a portfolio of leases with reasonably similar characteristics (remaining term, class of underlying asset, and economic environment).

Onerous leases

Prior to adoption, the Corporation assessed all leases under IAS 37 as an alternative to performing an impairment review subsequent to adoption. The right-of-use asset at the date of initial application will be adjusted by the amount of any provision for onerous leases recognized in the statement of financial position immediately before the date of initial application.

Short-term leases

Exclude leases from initial recognition for which the lease term ends within 12 months of the date of initial application or lease commencement.

Indirect costs

To exclude initial direct costs from the measurement of the right-of-use asset at the date of initial application.

Hindsight

To use hindsight, such as in determining the lease term if the contract contains options to extend or terminate the lease.

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

LEASES

ENMAX as Lessee

ENMAX assesses whether a contract is or contains a lease, at inception of the contract. ENMAX recognizes a right-of-use asset and a corresponding lease liability with respect to all lease arrangements in which it is the lessee, except for short-term and low-value leases. For these, ENMAX recognizes the lease payments as an operating expense on a straight-line basis over the term of the lease unless another systemic basis is more representative of the time pattern in which economic benefits from the leased assets are realized.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease. If this rate cannot be readily determined, ENMAX uses the incremental borrowing rate.

Lease payments included in the measurement of the lease liability comprise of the following:

- Fixed lease payments (including in-substance fixed payments), less any lease incentives.
- Variable lease payments that depend on an index or rate, initially measured using the index or rate at the commencement date.
- The amount expected to be payable by ENMAX under residual value guarantees.
- The exercise price of purchase options, if ENMAX is reasonably certain to exercise the options.
- Payments of penalties for terminating the lease, if the lease term reflects the exercise of an option to terminate the lease.

The lease liability is presented as a separate line in the condensed consolidated interim statement of financial position.

The lease liability is subsequently measured by increasing the carrying amount to reflect interest on the lease liability (using the effective interest method) and by reducing the carrying amount to reflect the lease payments made.

ENMAX remeasures the lease liability and makes a corresponding adjustment to the related right-of-use asset under the following conditions:

- The lease term changes or there is a change in the assessment of exercise of a purchase option, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.
- The lease payments change due to movements in an index or rate or a change in expected payment under a guaranteed residual value. In such cases the lease liability is remeasured by discounting the revised lease payments using the initial discount rate (unless the lease payments change is due to a change in a floating interest rate, in which case a revised discount rate is used).
- A lease contract is modified, and the lease modification is not accounted for as a separate lease, in which case the lease liability is remeasured by discounting the revised lease payments using a revised discount rate.

ENMAX did not make any such adjustments during the period presented.

The right-of-use assets are comprised of the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day and any initial direct costs. They are subsequently measured at cost less accumulated depreciation and impairment losses.

Whenever ENMAX incurs an obligation for costs to dismantle and remove a leased asset, restore the site on which it is located or restore the underlying asset to the condition required by the terms and conditions of the lease, a provision is recognized and measured under IAS 37. The cost is included in the related right-of-use asset, unless those costs are incurred to produce inventories.

Right-of-use assets are depreciated over the shorter period of lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that ENMAX expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. The depreciation starts at the commencement date of the lease.

ENMAX applies IAS 36 to determine whether a right-of-use asset is impaired and accounts for any identified impairment loss as described in the 'Property, Plant and Equipment' policy.

Variable rents that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset. The related payments are recognized as an expense in the period in which the event or condition that triggers those payments occurs and are included in the line 'Other expenses' in the statement of earnings or loss.

5. SEGMENT INFORMATION

The Corporation has core operations through two main business segments representing separately managed business units, each of which offers different products and services.

ENMAX COMPETITIVE ENERGY (COMPETITIVE ENERGY)

Competitive Energy is an operating segment established to carry out competitive energy supply and retail functions and the Calgary Regulated Rate Option (RRO) retail function 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 an 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 and residential development.

ENMAX POWER DELIVERY (POWER DELIVERY)

Power Delivery is a regulated operating segment established to own and operate electricity transmission and distribution assets in the Calgary service area through various legal entities and affiliated companies. Power Delivery's objective is to safely and efficiently operate and maintain the high reliability of its transmission and distribution system while meeting Calgary's power delivery infrastructure needs.

The final segment is ENMAX Corporate and Eliminations (Corporate and Eliminations). It is responsible for providing shared services and financing to ENMAX Competitive Energy and ENMAX Power Delivery. Certain comparative figures have been reclassified to conform to the current period's presentation.

SEGMENTED TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT BALANCES

As at *(millions of Canadian dollars)*	**September 30, 2019**	**December 31, 2018**
Competitive Energy	**2,739.8**	2,849.4
Power Delivery	**2,713.8**	2,551.4
Corporate and Eliminations	**182.8**	163.5
Total assets	**5,636.4**	5,564.3
Regulatory deferral account debit balances	**37.3**	82.0
Total assets and regulatory deferral account debit balances	**5,673.7**	5,646.3

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 unrealized gains and losses on commodities, foreign exchange, onerous provision recoveries on long-term contracts, and Emera Maine acquisition related costs, and are reflected in the column 'Adjusted Consolidated Totals' below.

Segment information as at September 30, 2018 has been reclassified to conform with the current year's presentation. The presentation change had no impact on reported consolidated net earnings.

Three months ended September 30, 2019 *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate and Eliminations**	**Adjusted Consolidated Totals**	**Regulatory Deferral Movement**	**Other Presentation Reclass**	**Consolidated Totals**
REVENUE							
Electricity	326.4	-	(31.8)	294.6	(0.1)	-	294.5
Natural gas	15.0	-	-	15.0	-	-	15.0
Transmission and distribution	-	189.4	-	189.4	(2.6)	-	186.8
Local access fees	-	37.4	-	37.4	-	-	37.4
Other revenue	47.9	9.2	(0.2)	56.9	(13.2)	-	43.7
TOTAL REVENUE	389.3	236.0	(32.0)	593.3	(15.9)	-	577.4
OPERATING EXPENSES							
Electricity and fuel purchases	237.8	-	(31.8)	206.0	-	(52.9)	153.1
Natural gas and delivery	6.4	-	0.1	6.5	-	-	6.5
Transmission and distribution	-	105.3	-	105.3	(16.7)	-	88.6
Local access fees	-	37.4	-	37.4	-	-	37.4
Depreciation and amortization	31.2	29.8	(1.0)	60.0	(0.1)	-	59.9
Other expenses	88.1	29.3	(0.6)	116.8	(14.3)	10.2	112.7
TOTAL OPERATING EXPENSES	363.5	201.8	(33.3)	532.0	(31.1)	(42.7)	458.2
OPERATING PROFIT (LOSS)	25.8	34.2	1.3	61.3	15.2	42.7	119.2
Unrealized gain on commodities				(52.9)	-	52.9	-
Foreign exchange loss				1.6	-	(1.6)	-
Emera Maine acquisition costs (1)				8.6	-	(8.6)	-
Finance charges (2)				18.6	-	-	18.6
NET EARNINGS BEFORE TAX				85.4	15.2	-	100.6
Current income tax expense				26.6	-	-	26.6
Deferred income tax expense				16.3	-	-	16.3
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				42.5	15.2	-	57.7
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	(15.2)	-	(15.2)
NET EARNINGS				42.5	-	-	42.5

(1) During the three months ended September 30, 2019, ENMAX recognized other expenses related to the acquisition of Emera Maine (see Note 18) of $8.6 million.

(2) During the three months ended September 30, 2019, ENMAX recognized finance charges related to the acquisition of Emera Maine (see Note 18) of $1.2 million.

Three months ended September 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	360.7	-	(32.7)	328.0	1.6	-	329.6
Natural gas	17.8	-	-	17.8	-	-	17.8
Transmission and distribution	-	170.5	-	170.5	3.0	-	173.5
Local access fees	-	39.7	-	39.7	-	-	39.7
Other revenue	37.0	8.5	9.0	54.5	(7.0)	-	47.5
TOTAL REVENUE	415.5	218.7	(23.7)	610.5	(2.4)	-	608.1
OPERATING EXPENSES							
Electricity and fuel purchases	269.8	-	(32.7)	237.1	-	(25.7)	211.4
Natural gas and delivery	8.9	-	(0.1)	8.8	-	-	8.8
Transmission and distribution	-	88.7	-	88.7	6.1	-	94.8
Local access fees	-	39.7	-	39.7	-	-	39.7
Depreciation and amortization	30.3	26.3	-	56.6	-	-	56.6
Other expenses	90.0	32.5	(6.3)	116.2	(7.4)	0.3	109.1
TOTAL OPERATING EXPENSES	399.0	187.2	(39.1)	547.1	(1.3)	(25.4)	520.4
OPERATING PROFIT (LOSS)	16.5	31.5	15.4	63.4	(1.1)	25.4	87.7
Unrealized gain on commodities				(25.7)	-	25.7	-
Foreign exchange loss				0.3	-	(0.3)	-
Finance charges				16.9	-	-	16.9
NET EARNINGS (LOSS) BEFORE TAX				71.9	(1.1)	-	70.8
Current income tax expense				1.3	-	-	1.3
Deferred income tax expense				6.2	-	-	6.2
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				64.4	(1.1)	-	63.3
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	1.1	-	1.1
NET EARNINGS				64.4	-	-	64.4

Nine months ended September 30, 2019 *(millions of Canadian dollars)*	**Competitive Energy**	**Power Delivery**	**Corporate and Eliminations**	**Adjusted Consolidated Totals**	**Regulatory Deferral Movement**	**Other Presentation Reclass**	**Consolidated Totals**
REVENUE							
Electricity	1,050.3	-	(98.9)	951.4	(0.1)	-	951.3
Natural gas	130.4	-	(0.1)	130.3	-	-	130.3
Transmission and distribution	-	549.3	-	549.3	10.1	-	559.4
Local access fees	-	105.7	-	105.7	-	-	105.7
Other revenue	128.1	26.8	(2.7)	152.2	(29.7)	-	122.5
TOTAL REVENUE	1,308.8	681.8	(101.7)	1,888.9	(19.7)	-	1,869.2
OPERATING EXPENSES							
Electricity and fuel purchases	798.8	-	(98.6)	700.2	-	(99.9)	600.3
Natural gas and delivery	89.5	-	0.2	89.7	-	-	89.7
Transmission and distribution	-	300.4	-	300.4	(27.5)	-	272.9
Local access fees	-	105.7	-	105.7	-	-	105.7
Depreciation and amortization	93.2	88.3	(3.0)	178.5	(1.5)	-	177.0
Other expenses	265.2	92.9	(3.6)	354.5	(31.8)	17.2	339.9
TOTAL OPERATING EXPENSES	1,246.7	587.3	(105.0)	1,729.0	(60.8)	(82.7)	1,585.5
OPERATING PROFIT	62.1	94.5	3.3	159.9	41.1	82.7	283.7
Unrealized gain on commodities				(99.9)	-	99.9	-
Foreign exchange loss				1.6	-	(1.6)	-
Emera Maine acquisition costs (1)				15.6	-	(15.6)	-
Finance charges (2)				58.4	-	-	58.4
NET EARNINGS BEFORE TAX				184.2	41.1	-	225.3
Current income tax expense				26.7	-	-	26.7
Deferred income tax expense				16.1	-	-	16.1
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				141.4	41.1	-	182.5
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	(41.1)	-	(41.1)
NET EARNINGS				141.4	-	-	141.4

(1) During the nine months ended September 30, 2019, ENMAX recognized other expenses related to the acquisition of Emera Maine (see Note 18) of $15.6 million.

(2) During the nine months ended September 30, 2019, ENMAX recognized finance charges related to the acquisition of Emera Maine (see Note 18) of $6.4 million.

Nine months ended September 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	1,014.5	-	(96.9)	917.6	1.8	-	919.4
Natural gas	117.0	-	(0.1)	116.9	-	-	116.9
Transmission and distribution	-	490.9	-	490.9	2.7	-	493.6
Local access fees	-	103.3	-	103.3	-	-	103.3
Other revenue	116.5	26.5	(2.4)	140.6	(12.9)	-	127.7
TOTAL REVENUE	1,248.0	620.7	(99.4)	1,769.3	(8.4)	-	1,760.9
OPERATING EXPENSES							
Electricity and fuel purchases	772.0	-	(97.0)	675.0	-	(28.5)	646.5
Natural gas and delivery	76.7	-	0.1	76.8	-	-	76.8
Transmission and distribution	-	256.6	-	256.6	21.7	-	278.3
Local access fees	-	103.3	-	103.3	-	-	103.3
Depreciation and amortization	90.1	79.9	-	170.0	-	-	170.0
Other expenses	252.8	102.9	(6.1)	349.6	(12.4)	(23.9)	313.3
TOTAL OPERATING EXPENSES	1,191.6	542.7	(103.0)	1,631.3	9.3	(52.4)	1,588.2
OPERATING PROFIT (LOSS)	56.4	78.0	3.6	138.0	(17.7)	52.4	172.7
Unrealized gain on commodities				(28.5)	-	28.5	-
Foreign exchange (gain)				(11.4)	-	11.4	-
Recovery of onerous provision [1]				(12.5)	-	12.5	-
Finance charges				52.1	-	-	52.1
NET EARNINGS (LOSS) BEFORE TAX				138.3	(17.7)	-	120.6
Current income tax expense				134.9	-	-	134.9
Deferred income tax expense				27.2	-	-	27.2
NET LOSS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				(23.8)	(17.7)	-	(41.5)
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	17.7	-	17.7
NET LOSS				(23.8)	-	-	(23.8)

[1] During the nine months ended September 30, 2018, ENMAX Competitive Energy segment recognized a recovery of its onerous provision by $12.5 million to reflect changes in circumstances associated with the expected timing and amounts of certain longer-term onerous contracts.

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 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 who do not negotiate a contract are supplied electricity on a regulated default supply contract.
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 their respective products 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 use of its electricity distribution system to deliver 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 September 30, 2019								
Electricity								
Competitive Energy	52.4	205.6	-	-	-	-	-	**258.0**
Regulated	29.8	6.7	-	-	-	-	-	**36.5**
Natural gas	12.5	2.5	-	-	-	-	-	**15.0**
Transmission & distribution	-	-	-	-	22.5	164.3	-	**186.8**
Local access fees	-	-	-	-	-	-	37.4	**37.4**
Contractual services	-	-	14.0	15.3	-	-	-	**29.3**
Other income & CIAC	-	-	-	14.4	-	-	-	**14.4**
TOTAL REVENUE	**94.7**	**214.8**	**14.0**	**29.7**	**22.5**	**164.3**	**37.4**	**577.4**

(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 September 30, 2018								
Electricity								
Competitive Energy	54.9	235.4	-	-	-	-	-	**290.3**
Regulated	31.1	8.2	-	-	-	-	-	**39.3**
Natural gas	13.4	4.4	-	-	-	-	-	**17.8**
Transmission & distribution	-	-	-	-	26.2	147.3	-	**173.5**
Local access fees	-	-	-	-	-	-	39.7	**39.7**
Contractual services	-	-	9.8	22.8	-	-	-	**32.6**
Other income & CIAC	-	-	-	14.9	-	-	-	**14.9**
TOTAL REVENUE	**99.4**	**248.0**	**9.8**	**37.7**	**26.2**	**147.3**	**39.7**	**608.1**

(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
Nine months ended June 30, 2019								
Electricity								
Competitive Energy	165.2	681.5	-	-	-	-	-	**846.7**
Regulated	82.5	22.1	-	-	-	-	-	**104.6**
Natural gas	97.3	33.0	-	-	-	-	-	**130.3**
Transmission & distribution	-	-	-	-	67.4	492.0	-	**559.4**
Local access fees	-	-	-	-	-	-	105.7	**105.7**
Contractual services	-	-	34.8	57.2	-	-	-	**92.0**
Other income & CIAC	-	-	-	30.5	-	-	-	**30.5**
TOTAL REVENUE	**345.0**	**736.6**	**34.8**	**87.7**	**67.4**	**492.0**	**105.7**	**1,869.2**
Nine months ended September 30, 2018								
Electricity								
Competitive Energy	163.3	653.8	-	-	-	-	-	**817.1**
Regulated	83.4	18.9	-	-	-	-	-	**102.3**
Natural gas	30.8	86.1	-	-	-	-	-	**116.9**
Transmission & distribution	-	-	-	-	67.5	426.1	-	**493.6**
Local access fees	-	-	-	-	-	-	103.3	**103.3**
Contractual services	-	-	36.5	61.2	-	-	-	**97.7**
Other income & CIAC	-	-	-	30.0	-	-	-	**30.0**
TOTAL REVENUE	**277.5**	**758.8**	**36.5**	**91.2**	**67.5**	**426.1**	**103.3**	**1,760.9**

6. 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 interests in generation facilities, liability positions arising from commitments to customers and transacting positions arising from hedging activities.

VALUATION OF DERIVATIVE ASSETS AND LIABILITIES

Financial derivative instruments are recorded at fair value on the condensed consolidated interim statement of financial position. As at September 30, 2019, the fair values of derivatives were as follows:

As at	**September 30, 2019**		**December 31, 2018**	
(millions of Canadian dollars)	**Hedge Instruments**	**Non-Hedge Derivatives**	**Hedge Instruments**	**Non-Hedge Derivatives**
Assets				
Current	**37.2**	**62.7**	22.2	36.1
Non-current	**12.9**	**29.5**	15.7	14.2
Liabilities				
Current	**12.1**	**76.4**	14.9	93.5
Non-current	**6.5**	**73.3**	20.8	114.4

For cash flow hedges, gains and losses are reclassified immediately to net earnings when anticipated hedged transactions are no longer likely to occur.

During 2019, the Corporation designated a cash flow hedging relationship for a proportion of the foreign exchange risk relating to the purchase price of Emera Maine, which is denominated in US dollars. The Corporation purchased forward contracts with an aggregate notional amount of $959.0 million US dollars to be exchanged throughout December 2019 and January 2020. The effective portion of the gains or losses on the forward contracts will be deferred in other comprehensive income (OCI) and will adjust the consideration for the Emera Maine business combination. The aggregate amount recorded in OCI to September 30, 2019 is a $4.2 million gain relating to this hedge and no ineffectiveness has been recorded.

For non-hedge derivatives, there were unrealized gains of $50.9 and $100.0 million for the three and nine months ended September 30, 2019, respectively (2018 - $25.9 and $31.4 million gain), primarily recorded in electricity and fuel purchases. The anticipated non-hedge derivatives are expected to settle in 2019 through 2032. 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 fair valued, 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	**September 30, 2019**		**December 31, 2018**	
(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	**49.5**	**50.2**	57.8	58.9
5–10 years	**29.0**	**31.4**	21.1	22.0
10–15 years	**222.2**	**259.5**	150.4	166.3
15–20 years	**586.8**	**651.7**	507.9	537.4
20–25 years	**426.6**	**448.5**	448.1	447.0
Private debentures				
Series 3 (3.81%)	**196.2**	**210.2**	199.0	203.0
Series 4 (3.84%)	**293.3**	**317.4**	298.3	301.2
Promissory note	**3.0**	**3.2**	3.3	3.4
	1,806.6	**1,972.1**	1,685.9	1,739.2

(1) Includes current portion of $74.6 million (December 31, 2018 – $71.3 million). Maturity dates range from June 2020 to June 2044.

As at September 30, 2019, ENMAX had $nil commercial paper (December 31, 2018 - $18.0 million, fair value of $18.0 million with an average interest rate of 2.25 per cent).

7. REGULATORY DEFERRAL ACCOUNT BALANCES

NATURE AND ECONOMIC EFFECT OF RATE REGULATION

ENMAX Transmission and ENMAX Distribution (the Divisions) are divisions of the ENMAX Power Delivery segment. The Divisions are regulated operations established to carry out all electrical transmission and distribution service functions within the City of Calgary. The AUC approves 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, 2019	62.8	10.8	8.4	82.0
Balances arising in the period [(1)]	87.1	(1.6)	5.2	90.7
Recovery (reversal) [(2)]	(108.4)	(1.5)	(8.5)	(118.4)
June 30, 2019	41.5	7.7	5.1	54.3
Balances arising in the period [(1)]	40.7	(1.1)	0.1	39.7
Recovery (reversal) [(2)]	(54.8)	-	(1.9)	(56.7)
September 30, 2019	**27.4**	**6.6**	**3.3**	**37.3**
Expected recovery/reversal period	3 Months	25 Years	12 Months	
January 1, 2018	34.4	9.9	31.9	76.2
Balances arising in the period [(1)]	86.2	1.0	1.7	88.9
Recovery (reversal) [(2)]	(65.9)	-	(6.6)	(72.5)
June 30, 2018	54.7	10.9	27.0	92.6
Balances arising in the period [(1)]	55.3	(0.5)	-	54.8
Recovery (reversal) [(2)]	(38.9)	-	(19.2)	(58.1)
September 30, 2018	**71.1**	**10.4**	**7.8**	**89.3**
Balances arising in the period [(1)]	26.2	0.4	2.0	28.6
Recovery (reversal) [(2)]	(34.5)	-	(1.4)	(35.9)
December 31, 2018	62.8	10.8	8.4	82.0
Expected recovery/reversal period	3 Months	25 Years	12 Months	

[(1)] "Balances arising in the period" row consists of new additions to regulatory deferral debits and credit balances.
[(2)] "Recovery (reversal)" row consists 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, 2019	-	5.0	5.0
Recovery (reversal) [(1)]	-	(1.8)	(1.8)
June 30, 2019	-	3.2	3.2
Balances arising in the period [(2)]	-	-	-
Recovery (reversal) [(1)]	-	(1.8)	(1.8)
September 30, 2019	**-**	**1.4**	**1.4**
Expected recovery/reversal period		12 Months	
January 1, 2018	-	9.4	9.4
Recovery (reversal) [(1)]	-	(0.2)	(0.2)
June 30, 2018	-	9.2	9.2
Balances arising in the period [(2)]	-	-	-
Recovery (reversal) [(1)]	-	(4.4)	(4.4)
September 30, 2018	**-**	**4.8**	**4.8**
Balances arising in the period [(2)]	-	0.1	0.1
Recovery (reversal) [(1)]	-	0.1	0.1
December 31, 2018	**-**	**5.0**	**5.0**
Expected recovery/reversal period		12 Months	

[(1)] "Recovery (reversal)" row consists of amounts collected/refunded through rate riders or transactions reversing existing regulatory balances.
[(2)] "Balances arising in the period" row consists of new additions to regulatory deferral debits and credit 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, that 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 represents 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 inter-company 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.

8. LEASES

ENMAX leases several assets categorized as: generation facilities and equipment, buildings and site development, land, tools, systems and equipment and vehicles. As at September 30, 2019, the average term remaining on the leases is 4.4 years.

Generation Facilities and Equipment

ENMAX leases a pipeline to supply the necessary water to one of its generation facilities. The term of this lease is 30 years with fixed payments over the life of the lease.

Buildings and Site Development

ENMAX has entered into building leases to house various operations. As at January 1, 2019, the leases that were capitalized have five to nine years remaining.

Land

In relation to several of ENMAX's generating facilities, additional land surrounding the facilities are leased to allow for the installation of substations and water reservoirs. The contracted lengths and terms of payments of the leases vary. As at January 1, 2019, ENMAX expects all land leases to be renewed until the end of the useful life of each respective generating facility.

Tools, Systems and Equipment

ENMAX has entered into a lease for various copiers and printers at its facilities. The lease term is for one year. At adoption it could not be reasonably determined if this lease would be renewed.

Vehicles

ENMAX leases vehicles that are mainly used by its field services crews for the installation and maintenance of the electrical system. The lease terms of the vehicles vary based on the specific use of the vehicle but are typically for five years.

Right-of-use assets

The changes in the net book value for the Corporation's right-of-use assets during the three and nine months ended September 30, 2019 were as follows:

(millions of Canadian dollars)	Generation Facilities and Equipment	Buildings and Site Development	Land	Tools, Systems and Equipment	Vehicles	Total
Cost						
As at January 1, 2019	5.1	-	-	-	-	5.1
Opening balance adjustment IFRS 16	27.9	13.3	8.8	0.1	7.7	57.8
Net Changes	-	(1.6)	-	-	1.6	-
As at June 30, 2019	33.0	11.7	8.8	0.1	9.3	62.9
Net Changes	-	-	-	-	(0.1)	(0.1)
As at September 30, 2019	**33.0**	**11.7**	**8.8**	**0.1**	**9.2**	**62.8**
Accumulated Depreciation						
As at January 1, 2019	1.7	-	-	-	-	1.7
Opening balance adjustment IFRS 16	-	-	-	-	-	-
Net Changes	0.6	0.8	0.1	0.1	1.3	2.9
As at June 30, 2019	2.3	0.8	0.1	0.1	1.3	4.6
Net Changes	0.3	-	0.1	-	0.6	1.0
As at September 30, 2019	**2.6**	**0.8**	**0.2**	**0.1**	**1.9**	**5.6**
Net Book Value						
As at January 1, 2019	3.4	-	-	-	-	3.4
As at September 30, 2019	**30.4**	**10.9**	**8.6**	**-**	**7.3**	**57.2**

Amounts recognized in profit and loss

(millions of Canadian dollars)	Three months ended September 30, 2019	Nine months ended September 30, 2019
Depreciation expense	1.0	3.9
Lease expense on short-term leases	-	0.2
Interest expense on lease liabilities	0.6	1.9
Amounts expensed in profit and loss	**1.6**	**6.0**

Lease payments

The required lease payments of the lease liability at September 30, 2019, are as follows:

As at September 30, *(millions of Canadian dollars)*	2019
Less than 1 year	**7.4**
1–5 years	**26.9**
More than 5 years	**55.9**

The total cash outflow for leases amounts to $1.9 million and $5.8 million for the three and nine months ended September 30, 2019. ENMAX does not face a significant liquidity risk with regards to its lease liabilities. Lease liabilities are monitored through ENMAX's treasury function.

9. DEFERRED REVENUE

As at *(millions of Canadian dollars)*	**CIAC**	**Other**	**Total**
January 1, 2019	533.6	17.0	550.6
Additions	8.6	4.1	12.7
Movements to PPE	(1.6)	-	(1.6)
Recognized as revenue	(9.4)	(0.5)	(9.9)
June 30, 2019	531.2	20.6	551.8
Additions	13.5	2.7	16.2
Movements to PPE	(0.4)	-	(0.4)
Recognized as revenue	(4.7)	(6.6)	(11.3)
September 30, 2019	**539.6**	**16.7**	**556.3**
Less: current portion	-	(6.9)	(6.9)
	539.6	9.8	549.4
January 1, 2018	501.5	13.5	515.0
Additions	19.6	2.9	22.5
Movements to PPE	(2.8)	-	(2.8)
Recognized as revenue	(8.6)	(1.6)	(10.2)
June 30, 2018	509.7	14.8	524.5
Additions	18.1	2.4	20.5
Movements to PPE	(1.0)	-	(1.0)
Recognized as revenue	(4.4)	(2.8)	(7.2)
September 30, 2018 (1)	522.4	14.4	536.8
Additions	20.0	2.8	22.8
Movements to PPE	(3.9)	-	(3.9)
Recognized as revenue	(4.9)	(0.2)	(5.1)
December 31, 2018	**533.6**	**17.0**	**550.6**
Less: current portion	-	(7.2)	(7.2)
	533.6	9.8	543.4

(1) Includes current portion of $5.7 million in other deferred revenue as at September 30, 2018.

10. OTHER ASSETS AND LIABILITIES

As at *(millions of Canadian dollars)*	September 30, 2019	December 31, 2018
Other current assets		
Prepaid expenses	**23.9**	9.2
Collateral paid	**11.6**	71.9
Deferred asset	**0.4**	0.3
Emission offsets	**38.6**	32.3
Other	**13.7**	5.2
	88.2	118.9
Other long-term assets		
Prepaid expenses	**6.5**	8.2
Long-term accounts receivable	**5.4**	2.5
Deferred asset	**4.4**	3.3
Other	**15.6**	13.1
	31.9	27.1
Other current liabilities		
Deposits	**28.1**	17.9
Other	**9.4**	6.9
	37.5	24.8
Other long-term liabilities		
Other	**11.9**	12.1
	11.9	12.1

11. 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 and nine months ended September 30, 2019, management adjusted the income tax provision using its best estimate with considerations including management's expectation of future operating results and interpretation of applicable tax positions and allowances, where uncertainty surrounding the realization of the tax benefit exists.

On June 28, 2019, The Alberta Bill 3 Job Creation Tax Cut (Alberta Corporate Tax Amendment) Act ("Bill 3") received Royal Assent and came into force. This newly enacted legislation is set to decrease the provincial corporate tax rate from 12 per cent to 11 per cent on July 1, 2019, with further 1 per cent rate reductions every year on January 1 until the general corporate tax rate reaches 8 per cent on January 1, 2022. This multi-year phased-in tax reduction is considered enacted for tax reporting purposes for the second quarter of 2019 and is therefore required to be reflected in the condensed consolidated interim financial statements.

Combined statutory tax rate (Federal and Alberta)

2019 (1)	26.5%
2020	25.0%
2021	24.0%
2022	23.0%

(1) Prorated statutory tax rate for 2019 taxation year based on ENMAX's December 31 year end.

12. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

As at *(millions of Canadian dollars)*	**September 30, 2019**	**December 31, 2018**
Net unrealized gains (losses) on derivatives designated as cash flow hedges, including deferred income tax expense of $8.5 million (December 31, 2018 - expense of $2.9 million)	**23.0**	(0.8)
Net actuarial losses on defined benefit plans, including deferred income tax recovery of $0.2 million (December 31, 2018 - recovery of $0.4 million)	**(4.1)**	(3.9)
Accumulated other comprehensive gains (losses), including deferred income tax expense of $8.3 million (December 31, 2018 - expense of $2.5 million)	**18.9**	(4.7)

13. OTHER REVENUE AND EXPENSES

	Three months ended September 30,		**Nine months ended September 30,**	
(millions of Canadian dollars)	**2019**	**2018**	**2019**	**2018**
OTHER INCOME				
Interest and penalty income	**2.5**	1.6	**7.4**	6.2
Miscellaneous	**7.2**	8.9	**9.0**	10.7
	9.7	10.5	**16.4**	16.9
OTHER EXPENSES				
Salaries and wages	**52.8**	51.9	**158.4**	183.7
Materials and supplies	**1.0**	3.7	**14.6**	14.1
Goods and services	**35.3**	34.3	**89.7**	96.0
Administrative and office expenses	**3.9**	2.8	**15.3**	8.5
Building expense	**15.7**	14.3	**56.9**	36.1
Vehicles and other	**2.5**	1.8	**3.5**	(1.2)
Onerous provision (recovery)	**-**	-	**-**	(12.5)
Foreign exchange losses (gains)	**1.5**	0.3	**1.5**	(11.4)
	112.7	109.1	**339.9**	313.3

14. DIVIDENDS

On March 13, 2019, the Corporation declared a dividend of $50.0 million to the City (2018 – $40.0 million). The dividend is paid in equal quarterly instalments during 2019.

15. CHANGE IN NON-CASH WORKING CAPITAL

(millions of Canadian dollars)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Accounts receivable	**(32.5)**	(23.5)	**89.8**	(8.7)
Regulatory deferral account debit balances	**17.0**	3.3	**44.7**	(13.1)
Other assets	**17.8**	25.9	**25.9**	12.3
Accounts payable and accrued liabilities	**10.3**	69.9	**(180.8)**	142.2
Regulatory deferral account credit balances	**(1.8)**	(4.4)	**(3.6)**	(4.6)
Other liabilities	**20.2**	(1.4)	**10.6**	(4.5)
Provisions	**-**	(0.4)	**(0.8)**	(14.6)
Change in non-cash working capital	**31.0**	69.4	**(14.2)**	109.0

16. 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.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF EARNINGS

(millions of Canadian dollars)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Revenue (1)	**44.0**	33.3	**114.7**	109.6
Local access fees and other expenses (2)	**39.1**	42.3	**109.8**	108.0

(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.

CONDENSED CONSOLIDATED INTERIM STATEMENTS OF FINANCIAL POSITION

As at *(millions of Canadian dollars)*	September 30, 2019	December 31, 2018
Accounts receivable	**23.7**	29.6
Property, plant and equipment (1)	**3.3**	3.4
Accounts payable and accrued liabilities	**12.4**	13.2
Long-term debt (2)	**1,314.1**	1,185.4
Other long-term liabilities (3)	**6.3**	6.3

(1) Assets under lease.
(2) Includes current portion of $74.2 million (December 31, 2018 $70.6 million), with maturities ranging from June 2020 to June 2044. In addition, the Corporation paid a management fee for the three and nine months ended September 30, 2019 of $0.8 million (2018 - $0.7 million) and $2.3 million (2018 - $2.1 million) respectively to the City.
(3) Includes 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's operations.

17. 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 and to long-term service arrangements on certain generating assets.

HISTORICAL TRANSMISSION LINE LOSS CHARGES

ENMAX has participated 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 invoicing 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 and C have been the subject of permission to appeal applications before the Alberta Court of Appeal as well as review and variance applications before the AUC.

The permission to appeal applications was heard by the Alberta Court of Appeal in the second quarter of 2018. On December 20, 2018 the Court issued a decision denying permission to appeal the AUC's decision on Module A and further reserving its decision on permission to appeal Module C and related matters. On June 3, 2019 the Court of Appeal of Alberta issued a decision denying permission to appeal the AUC's Model C decision. Since the Court did not grant permission to appeal Module A or Module C, the decision of the AUC will stand unless the Court's decision is further challenged.

Based on the Court's decision in Module A and Module C, management believes that ENMAX may be required to make material payments to the AESO for historical amounts. Because the AUC's previous decisions do not require the AESO to consider commercial agreement terms and service transfer circumstances when the AESO determines which party to invoice, ENMAX could be invoiced for amounts for which it may not ultimately, in whole or in part, be responsible. Moreover, the invoices may not reflect the benefit of credits to which ENMAX is entitled nor any of ENMAX's rights to subsequently seek compensation including under commercial agreements from other parties such as the Balancing Pool. The AESO currently expects to be in a position to issue invoices in April 2021, with initial settlement to occur in June 2021.

Management does not have the information necessary to calculate a reliable range of expected charges and credits across the portfolio of generation held during the relevant periods and the impact to ENMAX of such amounts. ENMAX believes it has sufficient access to cash to satisfy any amounts which may be required to be paid.

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 condensed consolidated interim financial statements when the amount can be reasonably estimated.

18. SIGNIFICANT EVENTS

On March 25, 2019, the Corporation announced that it had entered into a definitive agreement to acquire Emera Maine, a regulated electric transmission and distribution company in Maine, for a purchase price of $1,286 million. Including assumed debt, the aggregate enterprise value is expected to be approximately $1,800 million. This transaction is aligned with the Corporate strategy to grow regulated cash flows and diversify revenue streams within North America. The acquisition will raise ENMAX's regulated rate base by approximately 50 per cent and increase the portion of future cash flows from regulated and non-commodity sources to approximately 70 per cent. ENMAX intends to finance this transaction through a combination of a two-year bank loan, which is intended to be repaid before maturity, and private notes.

19. SUBSEQUENT EVENTS

On October 3, 2019, S&P Global provided an update on their rating for ENMAX, reducing the Corporation's credit rating to BBB and placing the ratings on CreditWatch with negative implications. The update was in response to ENMAX's plans to issue private debentures to partially fund the proposed acquisition of Emera Maine (see Note 18). DBRS continues to maintain ENMAX's current credit rating of A(low) and has placed the company under review – negative, citing an increase in financial risk due to the associated additional debt.

On October 15, 2019, the Corporation issued $850 million in unsecured private debentures with a weighted average interest rate of 3.35 per cent with maturities ranging from 2022 to 2029. The debentures have special mandatory redemption rights and will be held in escrow until the acquisition is complete.

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
AUC	Alberta Utilities Commission
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	Chartered 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
FCF	Free cash flow
FVTPL	Fair value through profit or loss
FVOCI	Fair value through other comprehensive income
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)
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
TIER	Technology Innovation and Emissions Reductions
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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