FINANCIAL REVIEW

ENMAX 2015

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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.

For further information, see the Management’s Discussion & Analysis (MD&A) section, Risk Management and Uncertainties.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A), dated March 16, 2016, is a review of the results of operations of ENMAX Corporation and its subsidiaries (ENMAX or the Corporation) for the year ended December 31, 2015, compared with 2014, and of the Corporation's financial condition and future prospects. This discussion contains forward-looking information that is qualified by reference to and should be read in light of the Caution to Reader previously mentioned.

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

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

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OUR BUSINESS

ENMAX is a wholly owned subsidiary of The City of Calgary (The City), headquartered in Calgary, Alberta, Canada. ENMAX's vision is to be Canada's leader in the electricity industry through its mission of powering the potential of people, businesses and communities by safely and responsibly providing electricity and energy services in a way that matters to them now and in the future. ENMAX and its predecessors have a proud history of providing Albertans with electricity for over 100 years and continue to explore ways to improve the province's electricity system and provide progressive solutions for its customers.

ENMAX's core operations include the competitive generation and sale of electricity across Alberta through ENMAX Energy, and the regulated transmission and distribution of electricity in the City through ENMAX Power:

- ENMAX Energy is involved in the generation of electricity in Alberta and controls its physical electricity supply through owned generation capacity and Power Purchase Arrangements (PPA). It purchases natural gas on the wholesale market with terms and conditions to meet the sales commitments of its retail marketing operations and for the operational requirements of its natural-gas-fuelled generating facilities. Risk-management processes and systems are in place to carefully monitor and manage price and commodity risks inherent in the business. ENMAX Energy is also Alberta's leading competitive electricity retailer. In addition to electricity, ENMAX Energy provides natural gas, renewable energy and value-added services to residential, commercial and industrial customers throughout Alberta.
- ENMAX Power owns and operates electricity transmission and distribution assets in the Calgary service area. In addition, it has the legislated responsibility to provide electricity for customers who elect to stay with the Regulated Rate Option (RRO). RRO is the default rate established by regulation and is automatically provided to all eligible customers who have not entered into a contract with a competitive electricity retailer. ENMAX Power has a subsidiary that provides engineering, procurement, construction and maintenance services. ENMAX Power's objective is to maintain the high reliability of its transmission and distribution system while meeting Calgary's growing infrastructure needs.

ENMAX Corporate, either directly or indirectly through its subsidiaries, provides billing and customer care services, shared services and financing to ENMAX Energy and ENMAX Power.

In order to support the execution of the strategy in serving our customers, our shareholder and stakeholders, the organization has been streamlined, with greater clarity of accountabilities beginning January 1, 2016. The organization structure continues to emphasize the two primary lines of business, ENMAX Energy and ENMAX Power. ENMAX Energy, the competitive business will now include Power Services, which provides engineering, procurement, construction and maintenance services as well as Customer Service. ENMAX Power will continue to own and operate the electricity transmission and distribution assets in Calgary area. These changes will be the first step in adapting to meet the changing environment and execute the Corporation's strategy.

MARKET CONDITIONS

The downward trend of oil prices in 2015 has adversely affected Alberta's economic expansion. Economic uncertainty and market volatility have resulted in lower activity and investment in the energy sector. As the year progressed, the weakness spread beyond the energy sector and has impacted the electricity market as well. Low demand growth and the general economic conditions have impacted power prices in Alberta. Furthermore, the provincial Government has announced climate change policies which have introduced significant uncertainty to the electricity sector.

OVERALL FINANCIAL PERFORMANCE

SELECTED CONSOLIDATED FINANCIAL INFORMATION

Year ended December 31 *(millions of dollars)*	**2015**	**2014**
Total revenue	**3,065.7**	3,457.0
Adjusted EBITDA [1]	**451.5**	427.1
EBIT [1]	**76.0**	237.3
Comparable Net Earnings [1]	**156.4**	192.9
Net Earnings	**48.7**	184.1

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

Despite the prevailing market conditions, ENMAX has posted strong financial performance in 2015 from each of its core businesses. ENMAX's adjusted EBITDA reflects higher operating margin in 2015 compared to 2014. The change in comparable net earnings is due to increased amortization and finance charges associated with the Shepard Energy Centre (Shepard) becoming operational and restructuring charges incurred in 2015. The decrease was partially offset by higher foreign exchange gains in 2015 and the non-recurring impact of the Keephills Unit 2 outage in 2014. The net earnings decrease for the year ended December 31, 2015 is primarily caused by the $144.4 million impairment of the Battle River Power Purchase Agreement (PPA).

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

NON-IFRS FINANCIAL MEASURES

Non-IFRS financial measures for ENMAX are provided below. 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.

EBITDA

Year ended December 31 *(millions of dollars)*	**2015**	**2014**
Adjusted EBITDA (non-IFRS financial measure)	**451.5**	427.1
Deduct:		
Depreciation and amortization	**228.8**	178.1
Finance charges	**68.7**	47.3
Income tax (recovery) expense	**(2.4)**	8.8
Comparable net earnings (non-IFRS financial measure)	**156.4**	192.9
Impairment	**146.7**	11.7
Income tax recovery on impairments	**(39.0)**	(2.9)
Net earnings (IFRS financial measure)	**48.7**	184.1

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

EBIT

Year ended December 31 *(millions of dollars)*	**2015**	**2014**
Operating profit (IFRS financial measure)	**119.1**	255.0
Adjustments for rate-regulated activities	**(43.1)**	(17.7)
EBIT (non-IFRS financial measure)	**76.0**	237.3
Deduct:		
Finance charges	**68.7**	47.3
Income tax (recovery) expense	**(41.4)**	5.9
Net earnings (IFRS financial measure)	**48.7**	184.1

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

FUNDS FROM OPERATIONS (FFO)

Year ended December 31 *(millions of dollars)*	**2015**	2014
Cash provided by operating activities (IFRS financial measure)	**526.7**	511.6
Changes in non-cash working capital	**(46.6)**	(47.1)
Employee future benefits	**0.6**	2.2
Contributions in aid of construction	**(43.2)**	(50.6)
Other	**-**	2.9
Funds from operations (non-IFRS financial measure)	**437.5**	419.0

FFO are used as an additional metric of cash flow without regard to changes in the Corporation's non-cash working capital and employee future benefits, and are adjusted for contributions in aid of construction (CIAC).

SIGNIFICANT EVENTS AND TRANSACTIONS

SHEPARD ENERGY CENTRE

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

GREENHOUSE GAS EMISSIONS

On June 25, 2015, the Alberta government announced plans to revise the province's climate change strategy. The first stage involves changes to Alberta's Specified Gas Emitters Regulation (SGER) to achieve a reduction in Alberta's greenhouse gas emissions. SGER sets emission intensity limits for facilities producing at least 100,000 tonnes of carbon dioxide. In the revised plan, the government increased the required emission intensity improvements from 12 per cent to 15 per cent in 2016 and to 20 per cent in 2017, along with an increase in compliance cost on every tonne that does not meet the improvement target from $15 per tonne to $20 per tonne in 2016 and $30 per tonne in 2017.

On November 22, 2015, the Alberta government announced the second stage of its climate change strategy, its Climate Leadership Plan. This plan outlined principles such as phasing out of coal generation by 2030 and replacing of two-thirds of coal-generated electricity by renewable energy sources, which would primarily be wind power. In the November 22, 2015 announcement, the government replaced SGER in 2018 with a new carbon tax formula. The formula is based on the intensity of the coal plant compared to a baseline that has yet to be determined but is likely to be tied to a natural gas emissions intensity measure. Moving to this new formula in 2018 will materially increase the carbon tax paid by coal plant operations. Under the Climate Leadership Plan, natural gas generation will provide more base-load supply as coal generation retires and becomes more costly. The Alberta government has indicated it will appoint an arbitrator to determine and provide details of the coal retirement and compensation elements of the climate leadership plan in 2016 so market participants will have a better understanding of the financial incentives or mechanisms the government will rely on to enact its strategy. The Corporation is expecting further details about the renewables element of the strategy.

BATTLE RIVER PPA

Effective January 1, 2016, ENMAX terminated its PPA relating to the coal–fired Battle River power plant. The termination was due to the PPA becoming unprofitable or more unprofitable as a result of changes to the SGER announced in June 2015. On January 1, 2016, ENMAX returned the PPA to Alberta's Balancing Pool. ENMAX has recorded an asset impairment charge of $144.4 million in 2015, which represents the remaining net book value of the Battle River PPA prior to the decision to terminate the PPA.

RESTRUCTURING COSTS

ENMAX has been engaged in an ongoing review of its organizational and cost structures to ensure that it is equipped to tackle the challenges and opportunities presented by the economy in general and within the electricity industry in particular. In late 2015, ENMAX implemented a reorganization that eliminated approximately 70 positions, resulting in annualized savings of approximately $9 million and positioning ENMAX to capture further savings through organizational efficiency. One-time costs of $11.2 million were incurred, consisting of $9.9 million of severance payments to employees and $1.3 million of consulting costs.

DIVIDEND

On March 16, 2016, the Corporation declared a dividend of $47.0 million payable to The City in quarterly instalments throughout 2016.

ENMAX ENERGY BUSINESS AND UPDATE

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

ENMAX Energy's core strategy is to grow its customer base across Alberta and invest in power generation facilities required to serve its electricity customers. ENMAX Energy supplies electricity through its own wind and natural-gas-fuelled generation facilities and PPA at Keephills Unit. Energy portfolio requirements are balanced through the purchase and sale of electricity and natural gas from and into wholesale Alberta markets. ENMAX Energy provides customers with competitive energy products and services with a focus on longer-term fixed electricity contracts. These contracts link customer demand to ENMAX Energy's generating assets, which results in relatively stable margins, even during times of volatile wholesale electricity prices.

Excluding any outages, as at December 31, 2015, ENMAX Energy's capacity ownership interest is 2,382 MW of electricity generation to supply customer demands. This excludes the Battle River PPA. The remaining power and all natural gas required to meet ENMAX Energy's consumer electricity and natural gas demand is acquired through the competitive wholesale power and natural gas markets. During times when ENMAX Energy has excess generation capacity, energy is sold to the market.

In addition to the above noted significant events, the following events impacted ENMAX Energy in 2015:

On March 11, 2015, the Keephills Unit 1 was producing near capacity when it was unexpectedly taken offline. The unit returned to service on May 21, 2015. The plant owner has claimed "force majeure" for this outage. Under a "force majeure," ENMAX Energy is not compensated for the outage by the owner for the duration of the outage but is relieved from paying certain capacity charges to the plant owner for the duration of the event.

Shepard experienced an unplanned outage in Q2, 2015. As a result, Shepard's available capacity was reduced in late May and the majority of June. Shepard was back online with full available capacity as of June 25, 2015.

KEY BUSINESS STATISTICS

	2015	2014
Plant availability (%) [1]	**94.79**	96.05
Average flat pool price ($/MWh)	**33.41**	49.62

[1] Plant availability includes planned maintenance and forced outages. Without incorporating the Shepard heat recovery steam generator (HRSG) outage, plant availability for the year ended December 31, 2015, was 90.98 per cent.

During 2015, ENMAX Energy experienced a decrease in the average flat pool price from 2014 levels. Power pool prices were lower as a result of an expected increased supply in the market, largely due to Shepard becoming operational in 2015 and availability performance at base-load facilities in Alberta, and reduced opportunities for the high price frequencies that have been experienced in recent years.

ENMAX POWER BUSINESS AND UPDATE

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

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

ENMAX Power submits applications to the Alberta Utilities Commission (AUC) to request the approval for the need to construct or replace utility related facilities, to set rates, or allocate costs related to the operation of providing energy-related services to Albertans. On April 30, 2015, the AUC initiated the 2016–2017 Generic Cost of Capital proceeding. In this proceeding, the AUC will approve a generic return on equity (ROE) value and deemed capital structures for regulated utilities in Alberta for the years 2016 and 2017 which will be used to determine the return ENMAX Power can recover from customers for its capital investments.

ENMAX Power filed an application with the AUC on December 18, 2015, requesting approval of its 2015-2017 Performance-Based Regulation (PBR) application. On May 8, 2015, the AUC initiated a generic proceeding on the parameters to be considered with respect to PBR plans for Alberta utilities, including ENMAX Power, commencing 2018. These two proceedings will determine the distribution rates that ENMAX Power will be able to charge customers from 2015 onward. The approved PBR rates and billing determinants (the measures of consumption used to calculate customers' bills) will ultimately determine ENMAX Power distribution's revenue.

In 2016, ENMAX Power expects to file an application to set its transmission revenue requirements for 2016 and 2017. A transmission revenue requirement is the amount of money that ENMAX Power will be paid to cover its costs, operating expenses, interest paid on debts, and a reasonable return (profit).

KEY BUSINESS STATISTICS

	2015	2014
Distribution volumes (GWh)	**9,454**	9,617
System average interruption duration index (SAIDI) [1]	**0.54**	0.48
System average interruption frequency index (SAIFI) [2]	**0.77**	0.99

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

[2] SAIFI equals how often the average customer experiences a sustained interruption over a predefined period of time. A sustained interruption has a duration greater than or equal to one minute.

Total electricity delivered in the Calgary service area for 2015 was slightly lower than the prior year. Electricity volumes of 9,454 gigawatt hours (GWh) were delivered during the year ended December 31, 2015, compared to 9,617 GWh during the year ended December 31, 2014. The decrease was primarily due to lower demand as a result of a relatively warm winter.

SAIDI results for year ended December 31, 2015 have increased over the prior year as ENMAX Power experienced one large outage during the year, had an increased in planned outages for capital maintenance work and outages due to a lightning storm in August. SAIFI results were lower in 2015 compared to 2014 due to fewer outages caused by pole fires and tree contact and reflect ENMAX Power's investment in distribution automation.

ENMAX FINANCIAL RESULTS

EARNINGS BEFORE INTEREST AND INCOME TAXES (EBIT COMPARED WITH THE SAME PERIOD IN 2014)

(millions of dollars)	ENMAX Energy	ENMAX Power	ENMAX Corporate	Consolidated
EBIT for the year ended December 31, 2014	134.6	99.2	3.5	237.3
Unusual items included in results:				
2014 Keephills Unit 2 outage[1]	17.4	-	-	17.4
Decisions impacting prior year included in transmission and distribution margin:				
2014 Recovery of earnings on capital[2]	-	(12.3)	-	(12.3)
2014 SAS Margin[2]	-	(5.8)	-	(5.8)
	152.0	81.1	3.5	236.6
Increased (decreased) margins attributable to:				
Electricity, excluding 2014 Keephills Unit 2 outage	1.2	(1.1)	0.1	0.2
Natural gas	13.7	-	0.2	13.9
Transmission and distribution[3]	-	15.5	-	15.5
Contractual services and other	(1.7)	(2.6)	3.3	(1.0)
Decreased (increased) expenses:				
Operation, maintenance & administration[4]	(20.2)	8.1	0.8	(11.3)
Foreign exchange	7.7	-	0.1	7.8
Amortization	(35.4)	(9.1)	(6.2)	(50.7)
Impairment	(135.0)	-	-	(135.0)
EBIT for the year ended December 31, 2015	(17.7)	91.9	1.8	76.0

[1] On November 27, 2013, TransAlta Corporation (TransAlta) notified ENMAX that it was removing Keephills Unit 2 from service and would subsequently claim "force majeure" under the Keephills PPA with respect to this planned outage. Keephills Unit 2 provides ENMAX Energy with approximately 340 MW of electricity through a PPA. On January 31, 2014, the Keephills Unit 2 generator was removed from service by its operator, TransAlta. The Keephills Unit 2 generator returned to service on March 15, 2014. ENMAX has not accepted or agreed to the claim of "force majeure" in relation to this outage and has entered into a dispute resolution process with TransAlta in accordance with the terms of the PPA. For the year ended December 31, 2014, the Keephills Unit 2 outage impact was $17.4 million.

[2] AUC ruling received in the second quarter of 2014 approving recovery of earnings on transmission capital invested in prior periods, as well as the disallowed of the retainment for System Access Service (SAS) margin in Power.

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

[4] Normalized to exclude impact of intercompany transactions with no consolidated impact.

Normalized electricity margins, which exclude the 2014 Keephills Unit 2 outage, for the year ended December 31, 2015 increased $0.2 million or 0.1 per cent compared to the prior year.

The comparable electricity margins in the year ended December 31, 2015, compared to the prior year were primarily driven by a net impact of lower natural gas prices, which decreased the cost to run natural-gas-fuelled plants, lower the settled pool price to supply electricity sales, and increased volumes on commercial fixed-price contracts. This lower cost of supply was partially offset by lower realized sales prices on commercial fixed-price contracts.

ENMAX Energy acquired two natural-gas-fuelled electricity generation facilities in the third quarter of 2014, and Shepard began commercial operations in March 2015. These three facilities resulted in higher volumes generated to supply retail sales in 2015 compared to 2014. Lower natural gas input costs enabled ENMAX Energy to capture a larger spread between contract selling prices and market prices. These increases in the year ended December 31, 2015, were partially offset by realized losses on hedges and lower than expected plant availability (PPAs and Shepard).

Natural gas margins for the year ended December 31, 2015 increased $13.9 million or 41.4 per cent compared to the prior year. The increase in the year ended December 31, 2015 is primarily due to decreased supply costs as a result of lower gas market prices to supply customers. This was achievable through the integrated business model and strategy. The lower costs were partially offset by lower sales volumes as a result of warmer temperatures in 2015.

For the year ended December 31, 2015, transmission and distribution margins, excluding recovery decisions impacting the prior year, increased $15.5 million or 6.1 per cent. The increase in transmission and distribution margins is due to an increase in interim rates in 2015 and excludes the $12.3 million impact of an AUC ruling received in the second quarter of 2014 in relation to prior years. It also excludes the System Access Services decision received in September 2014 for $5.8 million related to prior periods.

For the year ended December 31, 2015, contractual services and other revenues decreased $1.0 million or 1.4 per cent compared to the prior year. The decrease for 2015 is mainly attributable to insurance recoveries received in 2014 (related to the 2013 Calgary flood) and construction activity related to Light Rail Transit (LRT) projects that were completed in 2014. The impact of this decrease is partially offset by increased commercial projects, activity on maintenance contracts and activity on residential developer projects.

Operation, maintenance and administration (OM&A) for 2015 increased $11.3 million or 3.3 per cent from the prior year. The increase in the year was due to staff and operating expenses related to the September 2014 acquisitions of the Cavalier Energy Centre and Balzac Power Station, and Shepard becoming operational on March 11, 2015, as well as the restructuring charges incurred in 2015. These increases in OM&A expense were partially offset by a decrease in provisions on receivables, and a reduction in expenses related to the maintenance of assets in ENMAX Power.

For the year ended December 31, 2015, a net foreign exchange gain of $19.5 million was recognized compared to a gain of $11.7 million in the year ended December 31, 2014. Foreign exchange gains or losses were primarily the result of long-term service agreements and equipment purchases denominated in foreign currencies as well as associated foreign exchange hedges.

Amortization expense for the year ended December 31, 2015 was $228.8 million compared with $178.1 million in the same period in 2014. The increased charges were primarily the result of assets placed into service in 2015, as Shepard became operational and ENMAX recorded a full year of amortization from plants acquired in September 2014.

Impairment reserves for the year end December 31, 2015 was $146.7 million, $135.0 million higher than the $11.7 million in 2014. The 2015 impairment charge is largely due to ENMAX's decision to exercise its right to return the Battle River PPA to the Balancing Pool effective January 1, 2016, and therefore recognize an impairment of the full net book value of Battle River PPA. The termination was due to the PPA becoming unprofitable or more unprofitable as a result of changes to SGER announced in June 2015.

OTHER NET EARNINGS ITEMS

Finance charges in 2015 increased $21.4 million or 45.3 per cent compared to the prior year. The increase in 2015 was due to the interest costs no longer being capitalized as Shepard became fully operational in March 2015, and increased interest expense due to the issuance of long-term debt, partially offset by the non-reoccurrence of $20.7 million of settlement costs associated with the termination of the interest rate swaps in the first quarter of 2014.

Current and deferred income tax for the year ended December 31, 2015 decreased $47.3 million to a recovery of $41.4 million from a $5.9 million expense for the same period in 2014. The income tax recovery for the year ended December 31, 2015 was mainly due to the loss caused by the recognition of the impairment of assets, increased future tax rates and losses encountered in taxable entities. The year ended December 31, 2015 reflects the change in the Alberta corporate tax rate (a $3.7 million recovery) year to date.

OTHER COMPREHENSIVE INCOME

Other comprehensive income (OCI) illustrates earnings under the assumption of full income recognition of gains and losses on the market value of securities and derivatives otherwise treated as hedges of future period revenues and expenses. ENMAX uses derivatives to hedge electricity, natural gas, interest rate and foreign exchange exposures. For the year ended December 31, 2015, OCI totaled gains of $25.4 million, compared with losses of $41.8 million for the same period in 2014. OCI for 2015 primarily reflects the fair value changes in electricity, natural gas and commodity positions and a prior period settlement of interest rate swaps.

FINANCIAL CONDITION

SIGNIFICANT CHANGES IN THE CORPORATION'S FINANCIAL CONDITION

(millions of dollars, except % change)	December 31, 2015	December 31, 2014	$ Change	% Change	Explanation for Change
ASSETS					
Cash and cash equivalents	**143.7**	16.7	127.0	760%	The acquisition of Balzac and Cavalier reduces cash in 2014.
Accounts receivable	**504.7**	542.8	(38.1)	(7%)	Decrease due to timing of receipts, decreased electricity sales on commercial fixed-price contracts and lower natural gas sales volumes.
Property, plant and equipment (PPE)	**3,960.9**	3,840.4	120.5	3%	General capital additions partially offset by amortization.
Power purchase arrangements (PPA)	**55.1**	235.5	(180.4)	(77%)	Net book value of Battle River PPA fully impaired in 2015. The carrying value at December 31, 2015 represents Keephills Unit PPA.
LIABILITIES AND SHAREHOLDER'S EQUITY					
Accounts payable	**367.6**	419.8	(52.2)	(13)%	Mainly attributable to lower gas volumes and lower capital accruals.
Financial assets (liabilities) [1]	**(39.6)**	(51.0)	11.4	22%	Change in fair value of hedging instruments and settlement of interest rate swap.
Long term debt [1]	**1,712.8**	1,610.3	102.5	6%	Receipt of $189.2 million in new ACFA funding, offset by repayment of $19.9 million of non-recourse Kettles term financing and $66.9 million of regularly scheduled debt payments.

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

LIQUIDITY AND CAPITAL RESOURCES

TOTAL LIQUIDITY AND CAPITAL RESERVES

As at December 31, *(millions of dollars)*	**2015**	**2014**
Committed and available bank credit facilities	**850.0**	1,150.0
Letters of credit issued:		
Power pool purchases	**32.4**	65.3
Energy trading	**52.5**	37.5
Regulatory commitments	**91.4**	87.5
Asset commitments	**0.7**	2.0
PPAs	**57.8**	56.7
	234.8	249.0
Overdraft facilities	**-**	27.3
Remaining available bank facilities	**615.2**	873.7
Cash on hand	**143.7**	16.7
Total liquidity and capital reserves	**758.9**	890.4

Cash on hand increased to $143.7 million as at December 31, 2015, compared to $16.7 million at the same time last year.

CAPITAL STRATEGY

The business is funded with a view to maintaining a capital structure in line with ENMAX's strategy of maintaining a stable, investment-grade credit rating. ENMAX is pursuing target ratios for long-term debt to total capitalization at a maximum of 45 per cent. As at December 31, 2015, the long-term debt-to-total capitalization ratio is 42.9 per cent compared with 41.4 per cent at year end 2014. Standard & Poor's has assigned ENMAX a BBB+ rating with a stable outlook. Dominion Bond Rating Services has assigned a credit rating of A (low). These ratings provide reasonable access to debt capital markets.

The principal financial covenant in ENMAX's credit facilities is debt to capitalization.

CASH PROVIDED BY OPERATING ACTIVITIES

FFO for the year ended December 31, 2015 were $437.5 million, compared with $419.0 million in the same period in 2014. Cash provided by operating activities for the year ended December 31, 2015 was $526.7 million compared to $511.6 million in the same period in 2014. Both are largely due to improved operating margins.

INVESTING ACTIVITIES

The following table outlines investment in capital additions for the year ended December 31, 2015.

CAPITAL ADDITIONS *(millions of dollars)*	**2015**	**2014**
Residential and non-residential developments	**55.6**	46.9
AESO[1] required capital projects	**32.9**	61.3
System infrastructure	**35.1**	29.4
Asset replacement & modification	**71.4**	75.2
Information technology, facilities and tools	**33.5**	28.7
ENMAX Power	**228.5**	241.5
Shepard	**54.4**	124.5
Acquisition of generating assets	**-**	232.3
Other	**30.7**	36.7
ENMAX Energy	**85.1**	393.5
Other	**8.6**	24.3
Total	**322.2**	659.3

(1) Alberta Electric System Operator.

During the year ended December 31, 2015, ENMAX continued to execute its capital plans to meet the increasing need for electricity in Calgary.

FINANCING ACTIVITIES

ENMAX made regularly scheduled long-term debt principal payments of $87.2 million during the year ended December 31, 2015, compared with $58.8 million in the same period in 2014.

At December 31, 2015, cash and cash equivalents amounted to $143.7 million compared with $16.7 million at December 31, 2014. At December 31, 2015, overdraft on bank accounts was nil as compared with $27.3 million of overdrafts on bank accounts at December 31, 2014.

On March 19, 2015, ENMAX declared a dividend of $56.0 million payable to The City in quarterly instalments throughout 2015. All quarterly instalments of this dividend were paid by the end of 2015. On March 16, 2016, a dividend of $47.0 million was declared payable to The City in four quarterly instalments.

ENMAX has historically paid The City annual dividends of the higher of 30 per cent of the prior year's net earnings or $30.0 million. Dividends for a fiscal year are established in the first quarter of the same fiscal year. The payment and level of future dividends on the common shares will be affected by such factors as financial performance and ENMAX's liquidity requirements.

On March 12, 2015, ENMAX's unsecured credit facilities were amended as we resized our liquidity and resources, due to the completion of our major construction project Shepard, and to achieve a meaningful reduction in standby and other fees. The total unsecured credit facilities were reduced by $300.0 million to $850.0 million, with $600.0 million in bilateral credit facilites and $250.0 million of syndicated credit facilities. The letter of credit tranches amount to $300.0 million capacity with a July 20, 2018 expiry, and the operating tranches expiring on July 20 2020, now stand at $550.0 million.

RISK MANAGEMENT AND UNCERTAINTIES

ENMAX's approach to risk management addresses risk exposures across all of the Corporation's business activities and risk types. ENMAX utilizes an Enterprise Risk Management (ERM) program to identify, analyze, evaluate, treat and communicate the Corporation's risk exposures in a manner consistent with ENMAX's business objectives and risk tolerance.

Risk exposures are managed within levels approved by the Board and the Chief Executive Officer, and monitored by personnel in the business units, the planning and risk department, and the senior management team. At a management level, each accountability area is responsible for assessing its risk exposures and implementing risk treatment plans. ENMAX's planning and risk department coordinates an enterprise risk assessment process and provides risk reporting. Risk oversight is delivered through the Board and the Risk Management Committee (RMC), which is comprised of senior management members. Together, the RMC and Board oversee identified risk exposures and risk management programs, including the ERM program.

ENMAX's overall risk control environment includes:

- clearly articulated corporate values, principles of business ethics;
- published enterprise-wide policies and standards in key risk areas such as delegation of authority;
- documented commodity trading and position limits;
- an internal audit function to test compliance with internal controls and policies;
- regular reporting of risk exposures and mitigations, including insurance programs, to the RMC and Board;
- the use of industry-accepted tools and methodologies for assessing risk exposures; and
- a Safety and Ethics Help Line for employees to anonymously report suspected illegal or unethical behaviour.

These risk management programs and governance structures are designed to manage and mitigate a number of risk factors affecting ENMAX's business.

The following discussion does not consider the result of any inter-relationship among the factors.

MARKET RISK

ENMAX has inherent risk in positions in electricity and natural gas commodities arising from owned and controlled supply assets and demand obligations. ENMAX also purchases and sells these commodities in wholesale markets to manage such positions. While ENMAX's business model is designed to achieve a balanced portfolio, in the near term electricity and natural gas positions may experience periodic imbalances and result in exposures to price volatility from spot or short-term contract markets. In the longer term, where ENMAX has fewer fixed-price retail contracts, there is greater exposure to market price risk. The Outlook section of this report includes management's current view of the near-term risk to electricity prices.

ENMAX Energy utilizes numerous tools to forecast electricity consumption and generation, as well as the pattern of consumption and generation between peak and off-peak hours (load shape). However, it is not possible to hedge all positions every hour. As such, there is exposure to volume and load shape risk. ENMAX actively manages its supply portfolio to match generation to consumption volumes, and has facilities that allow for quick reaction to unexpected supply and demand factors. ENMAX Energy may also purchase blocks of electricity in the open market in advance of consumption in order to minimize exposure to extreme price fluctuations between off-peak and peak hours.

ENMAX may have future earnings variability with a moderate high impact as it relates to the sustainability and diversification of its portfolio. Furthermore, a valuation modelling error could produce earnings variability, which could also have a low impact. Overall commodity price levels have a potential earnings variability, which could have a high financial impact. Moderate-low impact earnings variability could also be seen as a result of retail residential and small business and industrial, commercial and institutional customer demand volatility, reducing retail margins or decreasing renewal and acquisition rates. ENMAX Energy uses derivative instruments, such as swaps and forwards, to manage exposure to commodity price risk. Financial gains and losses could be recognized as a result of volatility in the market values of these contracts. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these derivative instruments may involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts. The inability or failure to effectively hedge its energy portfolio and prevent financial losses from derivative instruments could adversely affect ENMAX's business, results of operations, financial condition or prospects of the Corporation. ENMAX's hedging strategies control and mitigate these commodity price risks. Occasionally, hedging is ineffective as it is based upon predictions about future market conditions and may require a minimum level of market liquidity to actively manage positions.

ENMAX has foreign exchange rate exposures arising from certain procurement and energy commodity business activity. ENMAX hedges the majority of its foreign exchange risk exposures as such exposures arise. However, such hedges may not be sufficient to cover foreign exchange exposure in the event of timing mismatches or extreme foreign exchange rate movements. This has a low earnings impact.

Changes in interest rates can impact borrowing costs and certain revenue streams from business activities. Substantially all of ENMAX's long-term debt is currently either fixed-rate amortizing debt or fixed-rate bullet debt. This structure effectively mitigates exposure to interest rate fluctuations in the near term. Short-term debt is generally variable rate, and long-term debt will need to be replaced at maturity leading to longer-term exposure.

For additional details on ENMAX's market risk exposures and sensitivities, refer to Note 7 in the Notes to the Consolidated Financial Statements.

OPERATIONAL RISK

ENMAX owns, controls or operates a number of electricity generation, transmission and distribution assets and facilities. The operation of such assets and facilities involves many risks, including: public safety incidents; start-up risks; breakdown or failure of generation, transmission or distribution facilities or pipelines; use of new technology; dependence on a specific fuel source, including the transportation of fuel; impact of unusual or adverse weather conditions, including natural disasters; and performance below expected or contracted levels of output or efficiency. Natural resource operating facilities are subject to weather-driven risks such as wind availability. There is risk of inadequate or failed internal processes, people and systems within the competitive and regulated businesses, shared services departments and certain outsource service organizations.

Breakdown or failure of a facility may prevent the facility from performing as expected under applicable agreements, which, in certain situations, could result in terminating the agreements or incurring a liability for damages. Unanticipated transmission and distribution outages can cause interruptions in service. Unanticipated generation facility outages or operations at lower-than-full capacity can cause periodic imbalances in ENMAX's electricity and natural gas positions. Weather conditions can materially affect the level of demand for electricity and natural gas, the prices for these commodities and the generation of electricity at certain facilities. In addition, demand obligations may fluctuate based on commodity prices, season, day and time of use, and specific customer requirements.

Events that could result from physical or cyber war, terrorism, civil unrest or vandalism may cause damage to ENMAX and its assets and have an impact on its generation, transmission and distribution operations or administrative functions in unpredictable ways.

These operational risks may affect ENMAX's ability to execute on its strategy in an effective and efficient manner, affect the quality of customer service, and result in lost revenues and/or increased costs. These risks are actively managed using incentives, site planning, controls, safety, security and insurance programs, in addition to a number of other measures within certain critical areas. ENMAX has implemented security measures and emergency response plans within certain critical areas.

ENMAX has obtained property, business interruption and other insurance coverage to mitigate some of these risk exposures, although such programs and measures may not prevent or cover the occurrence of any or all of these events and the adverse effects they may generate. There can be no assurance that ENMAX will be able to obtain or maintain adequate insurance in the future at rates the Corporation considers reasonable, that insurance will continue to be available on terms as favourable as the existing arrangements, or that insurance companies will meet their obligation to pay claims. Further, there can be no assurance that available insurance will cover all losses or liabilities that may arise in the conduct of ENMAX business.

Earnings could be affected by a regulated transmission blackout/brownout, failure of metering equipment or loss of communication services. Fuel supply shortages, failure of third-party services or infrastructure, human error, labour disruption, hazards to facilities and regulatory decisions could cause earnings variability. There has been and could be future exposure to moderate-high impact earnings variability due to a significant failure at a PPA plant (defined as a failure causing an outage of six months or longer) or due to the variation in the annual incentive payments to PPA operators. A high impact in earnings variability could also be seen as a result of the non-performance of contracted physical electricity or natural gas by counterparties.

ENVIRONMENTAL RISK

ENMAX is subject to regulation by federal, provincial and local authorities with regard to air, land and water quality and other environmental matters. The generation, transmission and distribution of electricity results in and requires disposal of certain hazardous materials, which are subject to these laws and regulations. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for non-compliance, including fines, injunctive relief and other sanctions. New environmental laws and regulations affecting ENMAX operations may be adopted and new interpretations of existing laws and regulations could be invoked or become applicable, which may substantially increase environmental expenditures in the future. New facilities or modifications of existing facilities may require new environmental permits or amendments to existing permits. Delays in the environmental permitting process, denials of permit applications, and conditions imposed in permits may materially affect the cost and timing of projects. Non-compliance with environmental laws and regulations or incurrence of new costs or liabilities could adversely affect the business, results of operations, financial condition or prospects of the Corporation. ENMAX has implemented various programs to manage environmental risk exposures, many of which focus on prevention of and preparedness for adverse events.

In 2007, the Government of Alberta passed the Climate Change and Emissions Management Act and Alberta's SGER to address the regulation of GHG emissions from certain facilities located in the province. Effective July 1, 2007, facilities emitting more than 100,000 tonnes of GHG per year are required to reduce their emissions intensity from an emissions intensity baseline. In June 2015, the Alberta government updated SGER increasing the carbon levy from $15 per tonne to $20 in 2016, and $30 in 2017. The carbon-emissions target cuts will increase from 12 per cent to 15 per cent in 2016, and 20 per cent in 2017. The companies responsible for these facilities have been given a number of options to allow them to comply with the SGER requirement, including making operational improvements to the facilities, buying eligible offsets to apply against their emissions, and contributing to a fund established for the purpose of investing in technology to reduce GHG emissions in the province. ENMAX has taken steps to substantially mitigate these impacts, including acquiring qualified credits from both wind-generation assets and purchases on the wholesale market. ENMAX continues to assess and monitor the implications that these changes in legislation may have on its business.

The federal GHG regulations received Gazette II publication in September 2012. The regulations require coal-generation facilities to reduce GHG emissions to the level of a combined cycle natural gas generation facility upon reaching the age of 45 to 50 years, depending on the unit's commissioning date. The new federal government has not yet indicated commitment to these targets. In addition to the GHG regulation, Environment Canada is continuing to develop a National Air Quality Management System that could include Base Level Industrial Emissions Requirements (BLIERs) for existing coal-fired generation units that could set new limits for nitrogen oxide (NOx) and sulfur oxide (SOx) emissions. ENMAX has and continues to advocate that the combination of the federal GHG regulation and existing Alberta criteria air contaminant regulation will result in similar emissions reductions so that BLIERs does not need to be implemented in Alberta.

ENMAX mitigates its exposure to environmental regulations by building and acquiring new generation capacity emitting fewer GHGs, purchasing emission reductions offsets, investing in environmentally improved technologies in its supply from PPAs, and developing workplace conservation programs. Overall, moderate earnings variability exposure is possible if ENMAX fails to comply with its Environmental Management System (EMS). Exposure to further moderate volatility is possible due to potential of spills, releases and fire from hazardous materials, or as a result of GHG emissions policy changes.

REGULATORY RISK

ENMAX operates in competitive and regulated sectors of the electricity and natural gas industries and is subject to regulation by federal, provincial and municipal governmental regulatory and market authorities. Oversight of industry regulations is provided by the Alberta Department of Energy, Alberta Utilities Commission, Market Surveillance Administrator, Alberta Electric System Operator, National Energy Board, North American Electric Reliability Corporation, U.S. Federal Energy Regulatory Commission and other agencies.

Regulations and regulatory decisions affect ENMAX's regulated business, ENMAX Power in a number of areas, including: allowed rates of return; capital structure; industry and rate structure; development and operation of transmission and distribution assets; acquisition, disposal, depreciation and amortization; and recovery of certain operating costs. ENMAX's competitive and regulated businesses ENMAX Energy and ENMAX Power are subject to a number of specific regulations established to help ensure Alberta's wholesale and retail electricity, and natural gas markets operate in a fair, efficient and openly competitive manner. ENMAX Power is a transmission and distribution system owner and an electrical utility that is regulated by the AUC. It is also subject to AUC regulatory oversight for the provision of the RRO, with ENMAX Energy being the exclusive RRO provider within the city. ENMAX Energy is an affiliated retailer of ENMAX Power and, along with ENMAX Power, must comply with general energy marketing regulations and the Code of Conduct Regulation, which preserves a level playing field for all retailers.

ENMAX cannot predict the future municipal, provincial or federal governments or their policies that may impact the development of regulation over ENMAX business or the ultimate effect that any changes to the regulatory environment may have on its business. The regulatory process or specific decisions by a regulator may restrict ENMAX's ability to grow earnings, recover costs or achieve a targeted ROE in certain parts of its competitive and regulated businesses, or cause delays in or impact business planning and transactions and increase costs. Non-compliance with laws or regulations or changes to the regulatory environment could adversely impact the business, results of operations, financial condition or prospects of the Corporation.

Regulatory decision timing is expected to result in delays to full revenue recognition, and therefore earnings, although this is mitigated at times by the use of interim rates.

ENMAX actively participates in the various regulatory processes that influence its business environment and operations. ENMAX actively monitors business activity that is subject to regulation and has implemented compliance programs to mitigate regulatory and political risk exposures. ENMAX is potentially exposed to financial impact as it relates to changes to existing as well as new or upcoming policies, protocols, standards, administrative orders or regulations that can have an impact on ENMAX activities and operations. ENMAX is also potentially exposed to financial impact in regard to regulatory decisions and matters related to generation operations.

HUMAN RESOURCES RISK

ENMAX is subject to workforce factors, including loss or retirement of key executives or other employees; availability of and ability to attract, develop and retain qualified personnel; collective bargaining agreements with union employees; and performance of key suppliers and service providers. A number of personnel with highly specialized knowledge, skills and experience are required to lead and operate competitive and regulated businesses and shared services departments. Failure to manage human resources risk could adversely affect the business, results of operations, financial condition or prospects of the Corporation. ENMAX has mitigated this risk by implementing a number of programs to attract, develop and retain personnel, including recruitment, career development, recognition and competitive compensation and benefits programs.

As at the end of 2015, unionized employees made up approximately 65 per cent of ENMAX's workforce. ENMAX believes it has an effective relationship with the Corporation's unions. There are risks that successful negotiations will not be completed with collective bargaining units on mutually agreeable terms. Difficulties in negotiating these agreements or continuing these programs could lead to higher employee costs, a work stoppage or strike, and attraction or retention rates below expectations. ENMAX has two collective bargaining agreements covering its workforce. The Canadian Union of Public Employees (CUPE) collective bargaining agreement has a three-year term that expires on December 31, 2016. The International Brotherhood of Electrical Workers (IBEW) collective bargaining agreement was renegotiated at the end of December 2014 for a three-year term set to expire on December 31, 2017. Exposure in relation to a breakdown in labour relations with either of the two unions is possible.

Earnings variability could result from workforce attraction and retention issues and, an aging workforce. However, initiatives such as employee engagement and a focus on workplace culture help mitigate this risk.

TECHNOLOGICAL RISK

ENMAX utilizes complex technologies in all aspects of the business, from generation through to information technology. Improvements in current technologies and development of new technologies could render certain existing technologies obsolete. Alternative energy technologies such as fuel cells, micro-wind turbines, cogeneration and solar photovoltaic cells have become more accessible and cost competitive. As research and development continues on these alternative technologies, they become more economically viable energy sources. As well, newly constructed facilities are able to incorporate more efficient technologies. New laws and environmental regulations can require upgrades to current facilities' technologies and/or introduce new competition to the market through subsidies to encourage the use of new technologies.

ENMAX's ability to interface with customers is managed through extensive billing and customer care information technology systems. New developments in information systems could render these billing and customer care systems obsolete. ENMAX actively monitors regulatory changes and the potential technological impacts of these changes and is also investing in the development of advanced alternative information management technologies. An information management failure, an overall operational system failure, failure of aging applications and infrastructure are all events that when combined, could result in moderate earnings volatility. As well, unauthorized access to confidential information and leakage of sensitive data could result in earnings variability. Finally, a loss of the data centre could result in earnings variability.

LIQUIDITY RISK

A need to raise additional capital may occur if cash flow from operations and sources of liquidity are insufficient to fund activities. Such additional capital may not be available when it is needed or on favourable terms for a number of reasons, including changes in market conditions or perceptions of the investment community. ENMAX may be required to post collateral to support certain contracts that were executed to hedge commodity positions. Downgrades to credit ratings by credit rating agencies could affect ENMAX's ability to access capital on favourable terms and within a desired time frame and could also increase the amount of collateral required to be provided to counterparties. ENMAX actively monitors its cash position and anticipated flows to achieve adequate funding levels and communicates regularly with credit rating agencies and the investment community regarding its capital position.

ENMAX offers a defined benefit (DB) pension plan for qualifying employees. Our contributions to the pension plan are based on periodic actuarial valuations, the next of which is being completed for December 31, 2016. For accounting purposes, as at December 31, 2015, the pension plan had an estimated deficit of $28.3 million ($45.0 million at December 31, 2014). The actual amount of contributions required in the future will depend on future investment returns, changes in benefits and actuarial assumptions. Failure to effectively manage financial resources and related exposures could adversely affect the business, results of operations, financial condition or prospects of the Corporation. To manage this risk, ENMAX engages expert pension managers and has investment policies and procedures in place to set out the investment framework of the funds, including permitted investments and various investment constraints. These policies and procedures are approved annually by the Human Resources and Governance Committee of the Board, which also actively monitors the performance of the pension plan.

Notwithstanding mitigation in place, ENMAX could be exposed to earnings variability if its credit ratings were to be downgraded, covenants were breached on recourse debt or insufficient liquidity was experienced. Liquidity risk is considered low in the one-year period.

For additional details on ENMAX's liquidity risk exposures, refer to Note 7 in the Notes to the Consolidated Financial Statements. For additional details on its pension plan, refer to Note 19 in the Notes to the Consolidated Financial Statements.

CREDIT RISK

ENMAX enters into agreements and engages in transactions with a number of external parties, including suppliers, service providers, retail customers and other counterparties. In such arrangements, exposure exists to counterparty credit risks and the risk that one or more counterparties may fail to fulfill their obligations, including paying for or delivery of commodities. These risks are often exacerbated during periods of sustained low commodity prices and tighter credit markets.

ENMAX has implemented a credit risk management program to mitigate its exposures to credit risk. While it seeks to manage credit risk exposure by considering creditworthiness before and after entering into such agreements, monitoring business activity against pre-defined credit limits and obtaining collateral when it is prudent to do so, ENMAX may not be able to identify and avoid all counterparties that are not creditworthy. Defaults by suppliers, service providers, retail customers and other counterparties could adversely affect the business, results of operations, financial condition or prospects of the Corporation.

ENMAX has credit and collections activities to monitor credit risk exposures and has implemented available measures to protect against any future losses. In specific situations, this includes but is not limited to a reduction of credit limits, requests for additional collateral, requirements for performance bonds on significant projects or restriction of new transaction terms.

Financial results could be affected as a result of industrial, commercial or institutional customer default or as a result of default by residential, small commercial and wholesale customers. For additional details on its credit risk exposures, refer to Note 7 in the Notes to the Consolidated Financial Statements.

DEVELOPMENT RISK

ENMAX's ability to successfully complete generation, transmission and distribution projects currently under construction, projects yet to begin construction, or capital improvements to existing assets in a timely manner and within established budgets is contingent upon many variables and subject to a variety of risks, some of which are beyond the Corporation's control. Should any such risks come to bear, ENMAX could be subject to additional costs, delays to the in-service dates of these projects, termination payments under committed contracts and/or the write-off of the investment in the project or improvement. In addition, while ENMAX's business model is designed to mitigate exposure to risks (much like the Corporation's strategy to fix development costs by contractually fixing the price with contractors), ENMAX may be required to purchase additional electricity or natural gas to fulfill demand obligations until these projects are completed.

ENMAX's ability to successfully identify, value, evaluate, complete and integrate new acquisition opportunities, organic growth opportunities and major capital projects is subject to risks, including increased competition for acquisition targets, capital and other resources resulting from consolidation of the industry and the performance of the Alberta economy as well as intervention by the Government of Alberta. Such business development challenges could adversely affect the business, results of operations, financial condition or prospects of the Corporation.

ENMAX's budgets for capital programs and projects on an annual basis and funding for specific approved capital programs and projects on an ongoing basis. ENMAX performs risk assessments and develops risk treatment plans for major capital programs and projects. Project performance relative to expectations is regularly reported to senior management and the Board, and any corrective measures are taken as required. Delays and overspending in the development of capital projects could affect ENMAX's financial results.

LEGAL RISK

ENMAX is occasionally subject to costs and other effects of legal and administrative proceedings, settlements, investigations, claims and actions, in addition to the effect of new or revised tax laws, rates or policies, accounting standards, securities laws and corporate governance requirements. Non-compliance with existing laws, resolution of legal actions and changes to the legal environment could adversely impact the business, results of operations, financial condition or prospects of the Corporation.

ENMAX reviews and actively monitors business activity that could be subject to public or private legal actions, including changes to certain legislation, contracts with outside parties and incidents or claims allegedly involving the Corporation, and programs have been implemented to mitigate ENMAX's legal risk exposures. The Corporation could experience earnings variability as it relates to: legal or regulatory action; an incident of material unauthorized communication; a breach of a material contract; payment in lieu of tax (PILOT) litigation or other litigation; or a material breach of legislation or rules.

CORPORATE STRUCTURE RISK

ENMAX conducts a significant amount of business through subsidiaries and joint ventures. The ability to meet and service debt obligations is dependent on the operational results of these investments and their ability to distribute funds to ENMAX. Any restrictions on the ability of these investments to distribute funds to ENMAX may affect the ability to service the corporate debt.

REPORTING/DISCLOSURE RISK

The application of critical accounting policies reflects complex judgments and estimates. These policies include industry-specific accounting applicable to regulated public utilities, accounting for pensions and derivative instruments. The adoption of new accounting standards or changes to current accounting policies or interpretations of such policies could adversely affect the business, results of operations, financial condition or prospects of the Corporation. ENMAX has implemented various programs to reinforce its Internal Control over Financial Reporting (ICFR), including periodic assessments of controls by internal and external auditors and review of certain disclosures by the Board.

TAX RISK

Prior to January 1, 2001, the legal entities comprising the ENMAX group of companies were not subject to federal or provincial income taxes based on an exemption for municipally owned corporations in the Canadian Income Tax Act (ITA). The exemption generally requires corporations be wholly owned by a municipality, and substantially all income must be derived from sources within the geographic boundaries of the municipality. Entities that do not meet these requirements are subject to income tax.

In 2001, the Government of Alberta introduced a PILOT regulation in conjunction with the deregulation of the Alberta utilities industry. The purpose of this regulation was to level the playing field between municipally owned tax-exempt entities and non-tax-exempt organizations participating in the competitive part of the electricity market, by requiring tax-exempt organizations to make a payment in lieu of taxes equal to what they would have had to pay if they were not tax-exempt. This regulation required municipally owned retailers and municipally owned PPA holders to remit PILOT payments to the Balancing Pool, based on the retail and commodity components of their electricity operations. PILOT regulations do not apply to those entities subject to tax under the ITA.

With the introduction of PILOT regulations in 2001, certain ENMAX entities experienced a change in tax status. This resulted in all PILOT-related assets (primarily the PPA-owned assets at that time) being deemed to be disposed of and immediately reacquired at fair market value for tax purposes effective December 31, 2000. Alberta Finance disagrees with ENMAX's fair market value for tax purposes and ENMAX has received reassessments and communications in respect of the taxation years 2001 through 2011 accordingly. ENMAX does not agree with the reassessments and has commenced the necessary steps to defend its positions through the formal appeals and litigation process. ENMAX expects this process to be successful and will evaluate all options should the appeals and litigation process result in an unfavourable outcome.

When Alberta Finance conducted its 2006 audit of ENMAX Energy Corporation and ENMAX PSA Corporation, it disagreed with the interest expense deducted on the PILOT returns. ENMAX Corporation loaned money to 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 2006 through 2011. ENMAX does not agree with the reassessments and has taken necessary steps to defend its positions through the formal appeals and litigation process. ENMAX expects this process to be successful and will evaluate all options should the appeals and litigation process result in an unfavourable outcome.

The Alberta Electric Utilities Act precludes municipally owned corporations competing in the electricity generation business from realizing a tax, subsidy or financing advantage as a result of their association with the municipality. Accordingly, ENMAX holds generation assets in entities that do not qualify for the income tax exemptions noted above.

The determination of the income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make certain judgments. Tax filings are subject to audit by taxation authorities, and the outcome of such audits may increase tax liabilities. Issues in dispute for audited years and audits for subsequent years are ongoing and in various stages of completion. The Corporation estimates and monitors any uncertain tax position and recognizes an income tax expense if and when it is probable that the disputes will result in some changes to the tax liability. As a consequence, earnings variability in relation to reassessments from Alberta Finance in regard to prior years' returns and other contingent tax liabilities is possible.

STRATEGIC RISK

ENMAX's business model and strategic direction are predicated on certain assumptions, including the long-term viability of the competitive and regulated businesses, benefits associated with holding each of these businesses, evolution of technology used in the industry and attractiveness of growth opportunities. While ENMAX believes these assumptions will remain valid in the future, significant changes to the overall business environment or other factors could cause ENMAX to re-evaluate its business model or strategic direction.

ENMAX has several competitors that operate in the electricity and natural gas markets where it serves customers. Competitors vary in size from small companies to large corporations, some of which have significantly greater financial, marketing and procurement resources than ENMAX. ENMAX Energy must also compete with the RRO service provided by various parties throughout Alberta in order to convince customers to select ENMAX Energy as their competitive retailer. Changes to the business environment (such as Alberta's Climate Change Leadership Plan) and failure to attract and retain customers could adversely affect the business, results of operations, financial condition or prospects of the Corporation. ENMAX could potentially see earnings variability as it relates to constraints on its growth targets for market share.

CLIMATE CHANGE AND THE ENVIRONMENT

ENVIRONMENTAL RISKS

Refer to the Risk Management and Uncertainties section for discussion regarding environmental risks.

TRENDS AND UNCERTAINTIES

Environmental matters cause certain trends and uncertainties to exist. Customers are becoming more attuned to the source of their energy. As a result, the need to offer energy from alternative production methods and renewable resources is increasing. Based on ENMAX's asset portfolio, it is positioned to offer consumers choices and progressive technologies that will help increase revenues should this trend continue to develop. The Home Solar program launched in 2011 provides residential and commercial customers the opportunity to generate their own solar power using grid-tied solar photovoltaic technology.

ENVIRONMENTAL LIABILITIES

Environmental liabilities recorded in ENMAX's financial statements include GHG liabilities. The GHG liabilities relate to electricity generated both from ENMAX's PPAs and ENMAX-owned generation facilities. These items have been reflected as liabilities in the Consolidated Financial Statements as at December 31, 2015. ENMAX continues to actively monitor the EMS and will continue to abide with current and future environmental regulations.

ENMAX currently has no outstanding litigation for environmental matters. There are no other material environmental liabilities at this time.

INTEREST OF EXPERTS

INDEPENDENT AUDITOR

ENMAX's external auditor is Deloitte LLP, Chartered Accountants, Suite 700, 850 – 2 Street SW, Calgary, Alberta, T2P 0R8. Deloitte LLP is independent with respect to ENMAX within the meaning of the Rules of Professional Conduct of the Institute of Chartered Professional Accountants of Alberta.

ACTUARY

ENMAX utilizes external professional services in relation to its employee benefits from Willis Towers Watson, Suite 1600, 111 – 5 Avenue SW, Calgary, Alberta, T2P 3Y6. Willis Towers Watson is independent with respect to ENMAX, as it has no equity interest in the Corporation and is compensated at a contracted fixed rate, regardless of the outcome of its reports.

LEGAL AND REGULATORY PROCEEDINGS

The Corporation is occasionally named as a party in various claims and legal proceedings that arise during the normal course of its business. The Corporation reviews each of these claims, including the nature of the claim and the amount in dispute. Although there is no assurance that each claim will be resolved in favour of the Corporation, the Corporation does not believe that the outcome of any claims or potential claims it is currently aware of will have a material adverse effect on the financial results or position of the Corporation, after taking into account amounts previously reserved by the Corporation. For further information, refer to Note 28 in the Notes to the Consolidated Financial Statements.

CONSOLIDATED FINANCIAL STATEMENTS

Contents

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The preparation and presentation of the accompanying consolidated financial statements of ENMAX Corporation are the responsibility of management and the consolidated financial statements have been approved by the Board of Directors (the Board). In management's opinion, the consolidated financial statements have been prepared within reasonable limits of materiality in accordance with International Financial Reporting Standards (IFRS). The preparation of financial statements necessarily requires judgment and estimation when events affecting the current year depend on determinations to be made in the future. Management has exercised careful judgment where estimates were required, and these consolidated financial statements reflect all information available to March 16, 2016. Financial information presented elsewhere in this report is consistent with that in the consolidated financial statements.

To discharge its responsibility for financial reporting, management maintains systems of internal controls designed to provide reasonable assurance that the Company's assets are safeguarded, that transactions are properly authorized and that reliable financial information is relevant, accurate and available on a timely basis. The internal control systems are monitored by management, and evaluated by an internal audit function that regularly reports its findings to management and the Audit, Finance and Risk Committee (AFRC) of the Board.

The consolidated financial statements have been examined by Deloitte LLP, the Company's external auditors. The external auditors are responsible for examining the consolidated financial statements and expressing their opinion on the fairness of the financial statements in accordance with IFRS. The auditors' report outlines the scope of their audit examination and states their opinion.

The Board, through the AFRC, is responsible for ensuring management fulfills its responsibilities for financial reporting and internal controls. The AFRC, which is comprised of independent directors, meets regularly with management, the internal auditors and the external auditors to satisfy itself that each group is discharging its responsibilities with respect to internal controls and financial reporting. The AFRC reviews the consolidated financial statements and annual financial report and recommends their approval to the Board. The external auditors have full and open access to the AFRC, with and without the presence of management. The AFRC is also responsible for reviewing and recommending the annual appointment of the external auditors and approving the annual external audit plan.

On behalf of management,

Gianna Manes
President and Chief Executive Officer

Helen Wesley, MBA, CFA
Executive Vice President and
Chief Financial Officer

March 16, 2016

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of ENMAX Corporation:

We have audited the accompanying consolidated financial statements of ENMAX Corporation, which comprise the consolidated statements of financial position as at December 31, 2015, December 31, 2014, and January 1, 2014, and the consolidated statements of earnings, consolidated statements of comprehensive income, consolidated statements of changes in shareholder's equity and consolidated statements of cash flows for the years ended December 31, 2015 and December 31, 2014, and the notes to the consolidated financial statements.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENT

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audit is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of ENMAX Corporation as at December 31, 2015, December 31, 2014, and January 1, 2014, and its financial performance and its cash flows for the years ended December 31, 2015 and December 31, 2014, in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants and Chartered Accountants
March 16, 2016
Calgary, Alberta

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at *(millions of Canadian dollars)*		December 31, 2015		December 31, 2014 (Note 29)		January 1, 2014 (Note 29)
ASSETS						
Cash and cash equivalents	$	**143.7**	$	16.7	$	80.6
Accounts receivable (Note 7)		**504.7**		542.8		583.6
Income taxes receivable (Note 8)		**118.8**		96.8		96.9
Current portion of financial assets (Note 7)		**34.6**		53.6		26.6
Other current assets (Notes 10)		**44.2**		26.9		13.4
		846.0		736.8		801.1
Property, plant and equipment (Note 12)		**3,960.9**		3,840.4		3,322.2
Power purchase arrangements (Note 13)		**55.1**		235.5		275.1
Intangible assets (Note 14)		**145.8**		128.9		115.2
Deferred income tax assets (Note 8)		**93.9**		58.2		66.8
Financial assets (Note 7)		**40.7**		14.5		24.3
Other long-term assets (Notes 7 and 10)		**21.2**		20.2		28.8
TOTAL ASSETS		**5,163.6**		5,034.5		4,633.5
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES (Note 9)		**34.5**		66.6		83.7
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	$	**5,198.1**	$	5,101.1	$	4,717.2
LIABILITIES						
Short-term debt (Note 15)	$	**-**	$	27.3	$	-
Accounts payable and accrued liabilities		**367.6**		419.8		434.9
Income taxes payable (Note 8)		**-**		0.6		-
Current portion of long-term debt (Notes 7 and 16)		**66.2**		62.6		63.7
Current portion of financial liabilities (Note 7)		**61.8**		95.8		29.0
Current portion of deferred revenue (Note 20)		**7.7**		12.1		5.2
Current portion of asset retirement obligations and other provisions (Note 17)		**2.7**		0.9		0.9
Other current liabilities (Notes 7 and 10)		**39.7**		30.2		20.1
		545.7		649.3		553.8
Long-term debt (Notes 7 and 16)		**1,646.6**		1,547.7		1,375.3
Deferred income tax liabilities (Note 8)		**83.1**		65.5		81.7
Post-employment benefits (Note 19)		**39.9**		56.4		43.2
Financial liabilities (Note 7)		**53.1**		23.3		47.9
Deferred revenue (Note 20)		**395.3**		360.5		330.4
Other long-term liabilities (Notes 7 and 10)		**16.8**		16.7		15.2
Asset retirement obligations and other provisions (Note 17)		**104.9**		98.1		69.0
TOTAL LIABILITIES		**2,885.4**		2,817.5		2,516.5
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES (Note 9)		**13.5**		2.5		1.9
SHAREHOLDER'S EQUITY						
Share capital (Note 18)		**280.1**		280.1		280.1
Retained earnings		**2,042.9**		2,050.2		1926.1
Accumulated other comprehensive loss (Note 21)		**(23.8)**		(49.2)		(7.4)
		2,299.2		2,281.1		2,198.8
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY	$	**5,198.1**	$	5,101.1	$	4,717.2

Commitments and contingencies (Note 28)
See accompanying Notes to Consolidated Financial Statements.

Gianna Manes

Gianna Manes, President & CEO

James Hankinson, AFRC Chairman

CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31, *(millions of Canadian dollars)*	**2015**	2014 (Note 29)
REVENUE (Note 6)		
Electricity	**$ 1,917.7**	$ 2,153.1
Natural gas	**358.5**	541.6
Transmission and distribution	**544.3**	498.8
Local access fees	**113.3**	131.3
Other revenue (Note 22)	**131.9**	132.2
TOTAL REVENUE	**3,065.7**	3,457.0
OPERATING EXPENSES (Note 6)		
Electricity and fuel purchases	**1,513.4**	1,766.6
Natural gas and delivery	**311.0**	508.0
Transmission and distribution	**231.8**	206.9
Local access fees and grid charges	**113.3**	131.3
Depreciation and amortization	**228.8**	178.1
Impairment (Notes 12, 13 and 14)	**146.7**	11.7
Other expenses (Note 22)	**401.6**	399.4
TOTAL OPERATING EXPENSES	**2,946.6**	3,202.0
OPERATING PROFIT	**119.1**	255.0
Finance charges (Note 25)	**68.7**	47.3
NET EARNINGS BEFORE TAX	**50.4**	207.7
Current income tax (recovery) expense (Note 8)	**(17.2)**	9.9
Deferred income tax (recovery) (Note 8)	**(24.2)**	(4.0)
NET EARNINGS —BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES	**91.8**	201.8
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES (Notes 6 and 9)	**(43.1)**	(17.7)
NET EARNINGS	**$ 48.7**	$ 184.1

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31, *(millions of Canadian dollars)*		2015		2014 (Note 29)
NET EARNINGS		**48.7**		184.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX				
Items that will not be reclassified subsequently to statement of earnings				
Re-measurement gains (losses) on retirement benefits, net of deferred income tax recovery of $nil (2014—$0.2) (Note 19)		**17.7**		(13.6)
Items that will be reclassified subsequently to statement of earnings				
Unrealized gains (losses) on derivatives designated as cash flow hedges, net of deferred income tax recovery of $0.6 (2014—$2.5 tax expense)		**(13.3)**		(3.2)
Realized losses (gains) on derivatives designated as cash flow hedges reclassified to net earnings, net of deferred income tax recovery of $3.1 (2014—$7.3 tax expense)		**21.0**		(25.0)
Other comprehensive income (loss), net of income tax		**25.4**		(41.8)
TOTAL COMPREHENSIVE INCOME	**$**	**74.1**	$	142.3

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

(millions of Canadian dollars)	Share Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
As at January 1, 2015	$ 280.1	$ 2,050.2	$ (49.2)	$ 2,281.1
Net earnings	-	48.7	-	48.7
Other comprehensive income, net of income tax	-	-	25.4	25.4
Total comprehensive income	-	48.7	25.4	74.1
Dividends (Note 24)	-	(56.0)	-	(56.0)
As at December 31, 2015	**280.1**	**2,042.9**	**(23.8)**	**2,299.2**
As at January 1, 2014	$ 280.1	$ 1,926.1	$ (7.4)	$ 2,198.8
Net earnings	-	184.1	-	184.1
Other comprehensive (loss), net of income tax	-	-	(41.8)	(41.8)
Total comprehensive income (loss)	-	184.1	(41.8)	142.3
Dividends (Note 24)	-	(60.0)	-	(60.0)
As at December 31, 2014 (Note 29)	$ 280.1	$ 2,050.2	$ (49.2)	$ 2,281.1

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31, *(millions of Canadian dollars)*	2015	2014 (Note 29)
CASH PROVIDED BY (USED IN):		
OPERATING ACTIVITIES		
Net earnings	**$ 48.7**	$ 184.1
Contributions in aid of construction	**43.2**	50.6
Amortization of customer contributions (Note 20)	**(12.7)**	(13.6)
Depreciation and amortization	**228.8**	178.1
Impairment	**146.7**	11.7
Finance charges (Note 25)	**68.7**	47.3
Income tax (recovery) expense (Note 8)	**(41.4)**	5.9
Change in unrealized market value of financial contracts	**(1.3)**	5.5
Post-employment benefits	**(0.6)**	(2.2)
Other	**-**	(2.9)
Change in non-cash working capital (Note 26)	**46.6**	47.1
Cash flow from operations	**526.7**	511.6
Interest paid[1]	**(61.8)**	(17.9)
Income taxes paid	**(1.9)**	(7.8)
Net cash flow from operating activities	**463.0**	485.9
INVESTING ACTIVITIES		
Purchase of PPE, PPA and intangibles (Notes 12, 13 and 14)	**(337.8)**	(377.9)
Capitalized borrowing costs[1] (Note 25)	**(14.7)**	(49.4)
Acquisition of generating assets	**-**	(225.1)
Cash flow (used in) investing activities	**(352.5)**	(652.4)
FINANCING ACTIVITIES		
Repayment of short-term debt	**(282.3)**	(2,064.2)
Proceeds of short-term debt	**255.0**	2,091.5
Proceeds of long-term debt	**189.1**	432.1
Repayment of long-term debt and interest rate swaps	**(89.3)**	(296.8)
Dividend paid (Note 24)	**(56.0)**	(60.0)
Cash flow provided by financing activities	**16.5**	102.6
Increase (decrease) in cash and cash equivalents	**127.0**	(63.9)
Cash and cash equivalents, beginning of year	**16.7**	80.6
CASH AND CASH EQUIVALENTS, END OF YEAR	**$ 143.7**	$ 16.7
Cash and cash equivalents consist of:		
Cash	**$ 103.1**	$ 16.1
Short-term investments	**40.6**	0.6

[1] Total interest paid $76.5 million (2014—$67.3 million) includes interest paid and capitalized borrowing costs.
See accompanying Notes to Consolidated Financial Statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF THE BUSINESS

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

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

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

The impacts of the transition to IFRS for comparative information are presented in Note 29. These consolidated financial statements have been prepared in accordance with IFRS.

BASIS OF MEASUREMENT

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

FUNCTIONAL AND PRESENTATION CURRENCY

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

3. CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

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

SIGNIFICANT ACCOUNTING JUDGMENTS

Significant judgments are used in the application of accounting policies related to the following areas:

(a) Impairment of long-lived assets

The Corporation makes assessment as to whether any indicators of impairment exist at each reporting date.

Where impairment indicators exist, assets are tested individually unless they generate cash inflows that are largely dependent of other assets. When cash inflows are dependent, individual assets are grouped into cash-generating units (CGUs), the smallest group of assets that generates independent cash inflows. The determination of CGUs is based on management's judgment.

(b) Leases

The Corporation assesses contract arrangements with third parties to determine if they contain a lease. When a lease exists and the Corporation is a lessee, the Corporation accounts for it as a finance lease if the arrangement results in substantially all risks and rewards of ownership being transferred from the lessor to the Corporation. If risks and rewards of ownership have not been transferred from the lessor, the lease is accounted for as an operating lease.

The Corporation does not have material contract arrangements under which the Corporation is a lessor.

(c) Income taxes

The calculation of the Corporation's current and deferred income taxes involves a degree of estimation and judgment. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation and establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities or the Balancing Pool of Alberta. In calculating income taxes, consideration is given to factors such as tax rates, non-deductible expenses, changes in tax law, allowances and management's expectations of future operating results.

SIGNIFICANT ACCOUNTING ESTIMATES

The Corporation makes significant estimates in the areas below:

(a) Electricity revenues and costs

By regulation, wire service providers are not required to submit final load settlement data on customer electricity usage until four months after the month in which such electricity was consumed. The Corporation uses processes and systems to estimate electricity revenues and costs, including unbilled consumption. Any changes to electricity revenues and costs arising from these estimation processes will be accounted for as a change in estimate in the period they occur.

(b) Useful lives of property, plant and equipment, and intangibles

Useful lives are determined based on past experience and current facts, taking into account future expected usage and potential for technological obsolescence.

(c) Impairment of long-lived assets

The Corporation conducts impairment tests on long-lived assets where impairment indicators exist. Long-lived assets are written down to their recoverable amount, which is the higher of value in use and fair value less costs of disposal. The determination of recoverable amount involves significant estimates, including timing of cash flows, expected future prices for inputs and outputs, expected usage of the assets and appropriate discount rates.

In December 2015, the Corporation determined that the Battle River PPA would be unprofitable or more unprofitable in light of low wholesale electricity prices and increased costs under the Alberta Specified Gas Emitters Regulation announced in June 2015. Accordingly, the Corporation exercised its right to terminate the arrangement, effective January 1, 2016. As a result of this decision, the Corporation recorded an impairment on the Battle River 5 PPA of $144.4 million (Note 13).

In December 2015, the Corporation also performed an impairment test of its other power generating assets organized into four distinct CGUs. The impairment test was calculated based on the net present value of cash flow projections incorporating estimates of annual revenues, expenses and capital expenditures to the end of each power generating asset's useful life. These estimates incorporate past experience and the Corporation's current view of future generating capacity and natural gas forward pricing. The Alberta power price and the after-tax discount rate are significant inputs used in determining the recoverable amount of each CGU. The Corporation gave considerations to externally available information related to future pricing of electricity and natural gas inputs when developing certain pricing assumptions. These external sources of information include market information from the Alberta Electric System Operator (AESO) and research firms serving the industry. A discount rate of 6.70 per cent after-tax was used for each CGU and reflects the market weighted average cost of capital (WACC) using a capital asset pricing model approach, giving consideration to the risks specific to each CGU and the risks embedded in the net cash flow projections. For all CGUs, the estimated recoverable amount exceeded the CGUs' respective carrying value, no impairment expense was required (Note 12). For all CGUs tested for impairment, if the long-term average power price and discount rate used in the impairment model were decreased by 5.00 per cent and increased by 0.50 per cent respectively, the net estimated recoverable amount would decrease by $396.0 million and $139.0 million, respectively, and fall below their respective carrying value. These sensitivity analysis are for illustration purposes and may not be representative, as a change in one variable would potentially be tempered by changes in other variables. For example, a decrease in power price may be offset by a decrease in input costs such as natural gas prices.

(d) Regulatory estimates

Certain estimates are necessary given that the regulatory environment in which the Corporation operates often requires amounts to be recorded at estimated values until finalization and adjustment, pursuant to subsequent regulatory proceedings or decisions.

(e) Retirement benefits

The Corporation consults with an actuarial specialist when setting the key assumptions used to estimate the post-employment benefits and the costs of providing post-retirement benefits. Key assumptions include future return on plan assets, retirement age, mortality rates, discount rates, future health care costs, salary escalation rates and claims experiences.

(f) Purchase price allocation

The Corporation allocates the purchase price of the acquisition to its identifiable assets acquired and liabilities assumed at their estimated fair values at the acquisition date. The allocation of purchase price involves many assumptions regarding the valuation of acquired tangible and intangible assets and liabilities assumed in the acquisition.

(g) Fair value measurements and valuation

Some of the Corporation's assets and liabilities are measured at fair value for financial reporting purposes. In estimating the fair value of an asset or liability, the Corporation uses market-observable data when available. When observable data is not available, the Corporation determines fair value using inputs other than quoted prices observable for the asset or liability, or valuation techniques with inputs based on historical data.

(h) Asset retirement obligations

Measurement of the Corporation's asset retirement obligations requires the use of estimates with respect to the amount and timing of asset retirements; the extent of site remediation required; and related future cash flows, inflation rates and discount rates.

(i) Income taxes

The Corporation estimates deferred income taxes based on temporary differences between the carrying value of assets and liabilities for financial reporting purposes, and their tax bases determined under the applicable tax laws. The carrying value of deferred income tax assets are reviewed at the end of each reporting period and are reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow the benefit of part or all of that deferred tax asset to be utilized. The tax effect of temporary differences is recorded as deferred tax assets or liabilities in the consolidated financial statements. The calculation of income taxes requires the use of judgment and estimates. If these estimates prove to be inaccurate, future earnings may be materially impacted.

(j) Allowance for doubtful accounts

The allowance for doubtful accounts reflects an estimate of the accounts receivable that are ultimately expected to be non-collectible based on factors, including the aging of accounts receivable, historical write-offs, assessments of the collectability of amounts from individual customers and general economic conditions.

4. SIGNIFICANT ACCOUNTING POLICIES

The policies applied in these consolidated financial statements are based on IFRS applicable as at December 31, 2015. These consolidated financial statements are authorized for issuance by the Board of Directors as of March 16, 2016.

CONSOLIDATION

The consolidated financial statements include the accounts of the Corporation and its subsidiaries. All intercompany transactions, balances and unrealized gains and losses from intercompany transactions are eliminated on consolidation, except as disclosed under Note 9. The consolidated financial statements of the subsidiaries are prepared for the same reporting period and apply accounting policies consistent with the Corporation.

Subsidiaries are fully consolidated from the date in which control is obtained by the Corporation until the date that control ceases. Control exists when the Corporation possesses power over the investee, has exposure or rights to variable returns from its involvement with the investee, and has the ability to use its power over the investee to affect its returns.

JOINT ARRANGEMENT

A joint arrangement is an arrangement in which two or more parties have joint control and must act together to direct the activities that significantly affect the returns of the arrangement. The Corporation classifies its interest in joint arrangements as either joint operations or joint ventures depending on the Corporation's rights to the assets and obligations for the liabilities. When making this assessment, the Corporation exercises judgments and considers the structure and contractual terms of the arrangement, as well as the legal form of any separate vehicles, in addition to all other relevant facts and circumstances.

Joint arrangements that provide all parties with rights to the assets and obligations for the liabilities are classified as joint operations. When the Corporation undertakes its activities under joint operations, the Corporation recognizes in relation to its interest in a joint operation:

- its assets, including its share of any assets incurred jointly;
- its liabilities, including its share of any liabilities incurred jointly;
- its revenue from the sale of its share of the output arising from the joint operation; and
- its expenses, including its share of any expenses incurred jointly.

Joint arrangements that provide all parties with rights to the net assets of the entities under the arrangements are classified as joint ventures. Joint ventures are accounted for under the equity method of accounting. Under this method, the Corporation's interests in joint ventures are initially recognized at cost and are adjusted thereafter to recognize the Corporation's share of profits or losses, movements in other comprehensive income, and dividends or distributions received.

When a corporation transacts with a jointly controlled entity of the Corporation, unrealized profits and losses are eliminated to the extent of the Corporation's interest in the joint venture.

REGULATORY DEFERRAL ACCOUNTS

The Corporation adopted IFRS 14, Regulatory Deferral Accounts, to continue to recognize amounts that qualify as regulatory deferral balances in accordance with the basis of accounting used immediately before transition to IFRS. A regulatory deferral account balance is any expense (or income) account that:

- is included, or expected to be included, by the rate regulator in establishing the rate(s) that can be charged to the customers; and
- would not otherwise be recognized as an asset or liability in accordance with other IFRS.

In accordance with this standard, the Corporation has presented regulatory deferral account debits and credits on a separate line in the consolidated statements of financial position. As well, the net movement in regulatory deferral accounts is presented on a separate line in the statement of earnings.

BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill while any deficiency of the purchase price below the fair value of the net assets acquired is recorded as a gain in the period of acquisition. The associated transaction costs are expensed when incurred.

FINANCIAL INSTRUMENTS

Recognition

Financial assets and liabilities are initially recognized at fair value when the Corporation becomes a party to the contractual provisions of the instrument. However, where the fair value differs on initial recognition from the transaction price and the fair value is not measured using entirely observable inputs, the instrument is recognized at the transaction price. Fair value of a financial instrument is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Corporation discloses more details about fair value of financial instruments in Note 7. In the case of instruments not measured at fair value through profit or loss, incremental directly attributable transaction costs are accounted for as an adjustment to the carrying amount, and in all other cases such transaction costs are expensed as incurred.

The Corporation evaluates contracts to purchase non-financial items, which are subject to net settlement (whether explicitly or in substance) to determine if such contracts should be considered derivatives or if they were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the entity's expected purchase, sale or usage requirements (“own use”). If such contracts qualify as own use, they are considered executory contracts outside the scope of financial instrument accounting.

The Corporation evaluates financial and non-financial contracts not measured at fair value through profit or loss to determine whether they contain embedded derivatives. An embedded derivative is a component of a hybrid (combined) instrument that also includes a non-derivative host contract—with the effect that some of the cash flows of the combined instrument vary in a way similar to a stand-alone derivative. For such instruments, an embedded derivative is separated where the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract and a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative.

Derecognition

Financial assets are derecognized when the rights to receive cash flows from the assets have expired or it transfers the financial instrument in a manner that qualifies for derecognition through transfer of substantially all risks and rewards or transfer of control.

Financial liabilities are derecognized upon extinguishment. A modification of a financial liability with an existing lender is evaluated to determine whether the amendment results in substantially different terms in which case it is accounted for as an extinguishment.

Classification

The financial instruments of the Corporation are classified in the following categories: financial assets and liabilities at fair value through profit or loss, loans and receivables, available for sale financial assets and other financial liabilities. The classification depends on the nature and purpose of the financial instrument and is determined at the time of initial recognition.

(a) Financial assets and liabilities at fair value through profit or loss (FVTPL)

A financial asset or liability is classified in this category if acquired principally for the purpose of selling or repurchasing in the short term or when the instrument is a derivative instrument that is not designated in a qualifying hedging relationship.

Financial instruments in this category are recognized initially and subsequently at fair value, with any gains and losses arising from changes in fair value recognized in earnings.

(b) Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. The Corporation's loans and receivables are comprised of cash and cash equivalents and accounts receivables, and are included in current assets due to their short-term nature.

Financial instruments in this category are initially recorded at fair value and subsequently carried at amortized cost using the effective interest rate method, with interest and other income earned from these financial assets recorded in earnings.

(c) Other financial liabilities

Other financial liabilities include accounts payable and accrued liabilities, short-term debt, long-term debt, and dividends payable.

Financial instruments in this category are initially recorded at fair value, net of any transaction costs incurred, and subsequently carried at amortized cost using the effective interest method.

PRESENTATION

Financial assets and liabilities are not offset unless they are with a counterparty for which the Corporation has a legally enforceable right to settle the financial instruments on a net basis and the Corporation intends to settle on a net basis.

IMPAIRMENT OF FINANCIAL ASSETS

An impairment of loans and receivables carried at amortized cost is recognized in earnings when the asset's carrying amount exceeds the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. A reduction in an impairment charge may be recognized if the decrease is related objectively to an event occurring after the impairment was recognized.

HEDGES

In conducting its business, the Corporation uses derivatives and other financial instruments, including swaps, futures, options and forwards to manage its exposure to certain market risks. Certain derivatives are designated as hedging instruments for accounting purposes when meeting certain effectiveness and documentation requirements at inception of the hedging relationship and on an ongoing basis. Effectiveness is measured with reference to the risk management objective and strategy for the hedged item.

The fair values of various derivative instruments used for hedging purposes are disclosed in Note 7. The fair value of a hedging derivative is classified as a non-current asset or liability when the remaining maturity of the hedged item is more than 12 months, and as a current asset or liability when the remaining maturity of the hedged item is less than 12 months.

Cash flow hedges are used to manage the variability of cash flows resulting from the purchase and sale of electricity and natural gas as well as interest rate and foreign exchange.

For cash flow hedges, changes in the fair value of the effective portion of the derivative designated in a hedging relationship are accumulated in other comprehensive income and recognized in net earnings during the periods when the cash flows of the hedged item are realized. Gains and losses on cash flow hedges are reclassified immediately to net earnings when the hedged item is sold or terminated early, or when a hedged anticipated transaction is no longer probable.

Where the hedged item continues to be probable of occurring but is no longer highly probable of occurring, the hedging relationship terminates. The accumulated amount in other comprehensive income is retained until the hedged transaction occurs or it is no longer probable of occurring.

For cash flow hedges, ineffectiveness is measured based on comparing the cumulative change in the fair value of the hedged item with the cumulative change in the fair value of the hedging instrument in absolute terms. If the cumulative change in fair value of the hedging instrument exceeds the cumulative change in fair value of the hedged item, ineffectiveness is recorded in profit or loss for the excess.

Changes in fair value of de-designated or discontinued hedges are recorded in earnings from the date of de-designation or discontinuation. The unrealized changes in fair value recorded prior to de-designation or discontinuation are reclassified from accumulated other comprehensive income to earnings when the relating hedged item is recognized in earnings.

FOREIGN CURRENCY TRANSLATION

Foreign currency transactions are translated into the functional currency using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of such transactions and from the translation at year-end exchange rates of monetary items and liabilities denominated in foreign currencies are recognized in the statement of earnings, except when deferred in equity as qualifying cash flow hedges.

Foreign exchange gains and losses are included on the statements of earnings within Other Expenses.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents consist of cash-on-hand balances with banks and investments in money market instruments with maturities within three months from the date of acquisition.

PROPERTY, PLANT AND EQUIPMENT

Items of property, plant and equipment (PPE) are measured at cost less accumulated depreciation and any impairment losses. The cost of self-constructed assets includes the cost of materials and direct labour, and any other costs directly attributable to bringing the assets to a condition suitable for their intended use. Subsequent costs are included in the assets' carrying amount or recognized as a separate asset, as appropriate, only when it is probable that the future economic benefits associated with the items will flow to the Corporation and the cost can be measured reliably. The carrying amount of a replaced asset is derecognized when replaced. Major overhauls and inspections are capitalized. Repairs and maintenance costs are charged to the statement of earnings in the period in which they are incurred.

Where significant parts of an item of PPE have different useful lives in relation to the total cost of the item, they are accounted for as separate items of PPE and are depreciated separately. Depreciation methods, useful lives and residual values are reviewed at least at each financial year end and adjusted, if appropriate.

Depreciation of PPE is recorded on a straight-line basis over the estimated useful life of the asset class at the following rates:

Buildings and site development	0.61%	–	5.52%
Generation facilities and equipment	2.00%	–	20.00%
Generation overhauls and inspections	9.02%	–	67.11%
Tools, systems and equipment	4.74%	–	25.00%
Vehicles	2.36%	–	8.00%

Construction in progress represents assets that are not yet available for use and therefore not subject to depreciation. Capital spares and inventory are not amortized until they are reclassified and put into use as other equipment.

Gains or losses on disposal of an item of PPE are typically determined by comparing the proceeds from disposal with the carrying amount of PPE and are recognized in earnings.

For transmission, distribution and substation equipment depreciated using the group life depreciation method (regulated depreciable assets), with depreciation rates ranging from 0.00% to 22.72%, gains or losses on the disposal of regulated depreciable assets are typically deferred and amortized over the estimated remaining service life of the related regulated depreciable assets. Gains or losses on the disposal and retirement of regulated depreciable assets outside the course of normal business are charged or credited to earnings.

CONTRIBUTIONS IN AID OF CONSTRUCTION (DEFERRED REVENUE)

Under various statutory requirements and agreements with customers and developers, the Corporation receives contributions in aid of construction (CIAC) in the form of cash contributions. Such contributions are recorded as deferred revenue when funds are expended and recognized into other revenue over the useful life of the underlying asset to which the contribution related.

GOVERNMENT GRANTS

Government grants are not recognized until there is reasonable assurance that the Corporation will comply with the conditions attached to them and that the grants will be received. Government grants received for the purchase of certain items of PPE are deducted from the carrying amount of the related asset. Amounts received related to expense reimbursement reduce the expense in the period in which it is incurred.

CAPITALIZATION OF BORROWING COSTS

Borrowing costs directly attributable to the construction of a qualifying asset are eligible for capitalization. Qualifying assets are assets for which a substantial period of time is required to prepare the asset for its intended use. The Corporation borrows funds to finance its capital construction projects. The borrowing costs are capitalized, until construction is completed, at a rate based on the actual costs of debt used to finance the capital construction projects. Capitalized borrowing costs cannot exceed the actual cost incurred to borrow the funds.

POWER PURCHASE ARRANGEMENTS (PPAs)

The cost to acquire the PPAs has been recorded on the statement of financial position as an intangible asset. The cost is amortized based on available capacity per PPA unit over the term of the PPA. At the end of each reporting period, the carrying amount of the intangible asset is reviewed for indicators of impairment and tested for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable.

INTANGIBLE ASSETS

Intangible assets are recorded at cost and amortization is recorded on a straight-line basis over the estimated useful lives of the assets at the rates opposite:

Intangible assets with indefinite lives include some land easements, renewable energy certificates and water licenses, and are not subject to amortization. These assets are assessed annually for impairment or more frequently if events or changes in circumstances indicate that the asset may be impaired.

INTANGIBLE AMORTIZATION RATES

Renewable energy certificates and water license			11.00%
Customer lists and contracts			10.00%
Computer systems	2.81%	–	25.00%
Land easements, rights and lease options	1.79%	–	25.86%

ASSET IMPAIRMENT

Long-lived assets and intangible assets with finite lives are tested for impairment when events or changes in circumstances indicate possible impairment. Test for impairment is performed at the CGU level. Impairment loss is recognized in the statement of earnings if the recoverable amount of a CGU is estimated to be less than its carrying amount. The recoverable amount is the higher of fair value less costs of disposal and value in use. Impairment losses recognized in prior periods are assessed at each reporting date for indications that the loss has decreased or no longer exists. The impairment loss can be reversed up to the original carrying value of the asset that would have been determined, net of depreciation, had no impairment loss been recognized. A reversal of impairment is recognized immediately in the statement of earnings.

POST-EMPLOYMENT BENEFITS

The Corporation sponsors pension plans that contain both defined contribution (DC) and defined benefits (DB) provisions.

For DC pension plans, the Corporation's obligations for contributions are recognized as Other Expenses in the statement of earnings when services are rendered by employees.

For DB pension plans and other post-employment benefits, the level of benefit provided is based on years of service and earnings of the person entitled. The service cost of DB pension and other post-employment benefits earned by employees is actuarially determined using the projected unit credit method pro-rated on service and management's best estimate of expected health care costs. The related pension liability recognized in the statement of financial position is the present value of the DB and post-retirement benefit obligation at the statement of financial position date less the market value of the plan assets.

Actuarial valuations for defined benefit plans are carried out every three years at December 31. The discount rate applied in arriving at the present value of the pension liability represents yields on high-quality Canadian corporate bonds that have terms to maturity approximating the terms of the related pension liability.

Components of DB costs include service cost, net interest on the net DB liability and re-measurements of the net DB liability. Service cost is recognized as Other Expenses in the statement of earnings. Net interest is calculated by applying the discount rate to the net DB liability at the beginning of the annual period and takes into account projected contributions and benefit payments during the period. The net interest is recognized as interest expense in the statement of earnings. Re-measurement gains and losses, resulting from experience adjustments and changes in assumptions used to measure the accrued benefit obligation, are recognized in full in the period in which they occur through other comprehensive income.

LEASES

When an arrangement is entered into for the use of items of PPE, the Corporation evaluates the arrangement to determine whether it contains a lease. A specific asset would qualify as a lease if fulfillment of the arrangement is dependent on the use of the specific asset. An arrangement constitutes the right to use the asset if the Corporation has the right to control the use of the underlying asset. When an arrangement is determined to be a lease, the Corporation classifies the lease as either operating or financing depending on whether substantially all the risks and rewards of the asset have been transferred.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (ARO) are provisions for legal and constructive obligations for decommissioning and restoring the Corporation's generating assets and the Corporation's share of jointly-operated generating assets.

The estimated cash flows of the asset retirement costs are risk adjusted and discounted using a pre-tax, risk-free rate that reflects the time value of money. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset and then amortized over its estimated useful life. Changes due to revisions to discount rates, the timing or the amount of the original estimate of the provision are reflected on a prospective basis by adjusting the carrying amount of the related PPE.

PROVISIONS AND CONTINGENCIES

A provision is a liability of uncertain timing or amount. Provisions are recognized when the Corporation has a present legal or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation, and the amount can be reliably estimated. Provisions are measured at management's best estimate of the expenditure required to settle the obligation at the end of the reporting period and are discounted to present value where the effect of discounting is significant. A pre-tax, risk-free rate is used to discount estimated future risk-adjusted cash outflows. The unwinding of the discount (accretion) is recognized as a finance cost. The Corporation re-measures provisions each reporting period, taking into account changes in the likelihood and timing of future outflows and changes in discount rates.

The Corporation performs evaluations to identify onerous contracts and, where applicable, records provisions for such contracts.

REVENUE RECOGNITION

Revenue is recognized to the extent that it is probable that the economic benefits will flow to the Corporation and the revenue can be reliably measured. Revenue is measured at the fair value of the consideration received and is reduced for rebates and other similar allowances.

Electricity and gas

Revenue from the sale of electricity and gas is recognized when all of the following conditions are satisfied:

- the Corporation has transferred to the buyer significant risks and rewards of ownership of the commodity sold;
- the Corporation retains neither continuing managerial involvement to the degree usually associated with ownership nor effective control over the commodity sold;
- the amount of revenue can be measured reliably;
- it is probable that the economic benefits associated with the transaction will flow to the Corporation; and
- the costs incurred or to be incurred in respect of the transaction can be measured reliably.

Transmission and distribution

Revenues are recognized in a manner that is consistent with the underlying rate decision as mandated by the Alberta Utilities Commission (AUC).

Revenues are recognized on an accrual basis as services are provided and include an estimate of fees for services provided but not yet billed.

Rendering of services

Revenue from a contract to provide services is recognized by reference to the stage of completion of the contract. The stage of completion of the contract is measured by reference to costs incurred to date as a percentage of total estimated costs for each contract. The estimation of the total costs is reviewed on a monthly basis. Where the contract outcome cannot be measured reliably, revenue is recognized only to the extent that the expenses recognized are recoverable.

Where costs are expected to exceed revenues in a contractual commitment, the loss is recognized immediately in the statement of earnings and a provision made for the onerous amount.

EMISSION CREDITS AND ALLOWANCES

Effective July 1, 2007, the Climate Change and Emissions Management Amendment (CCEMA) Act was enacted into law in Alberta. The CCEMA Act, and regulations made pursuant to it, establishes baseline emission intensity levels for each large generating facility, and emissions over this baseline are subject to a surcharge. Changes in law provisions in the Corporation's PPAs have the potential to expose the Corporation to significant portions of these compliance costs (see Note 28).

Purchased emission allowances are recorded on the statement of financial position as part of other assets, at historical cost, and are carried at the lower of weighted average cost and net realizable value. Allowances granted to the Corporation or internally generated from approved projects are accounted for as other assets.

The Corporation has recorded emissions liabilities on the statement of financial position, as a component of accounts payable and accrued liabilities, using the best estimate of the amount required to settle the obligation in excess of government-established emission intensity levels. To the extent compliance costs are charged to the Corporation under the change in law provisions of the Corporation's PPAs, these amounts are recognized as cost of electricity services provided in the period they are levied.

DIVIDEND

Dividend revenue from investments (other than associates and subsidiaries) is recognized when the shareholder's right to receive payment has been established.

Dividends on common shares are recognized in the Corporation's consolidated financial statements in the period in which the dividends are approved by the Board of Directors of the Corporation.

INCOME TAXES

The Corporation and its subsidiaries operating in the province of Alberta in the country of Canada are municipally owned and are generally not subject to federal and provincial income taxes. Some subsidiaries exempt from federal and provincial income taxes calculate and make payments on certain portions of the operations based on the payment in lieu of tax regulation (PILOT) to the Alberta Electric Utilities Act (EUA). These PILOT payments are made to the Balancing Pool of Alberta. Those subsidiaries that do not meet the criteria for municipal exemption are taxable under the Income Tax Act (ITA) and the Alberta Corporate Tax Act (ACTA). Any further reference to income tax recognizes the combined obligations under PILOT, the ITA, and the ACTA.

The Corporation recognizes current and deferred income tax in the profit or loss for the period, except to the extent that it relates to a business combination or other transactions that are directly recognized in equity or other comprehensive income.

The calculation of the Corporation's total income tax expense involves a degree of estimation and judgment, and management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation and establishes provisions where appropriate on the basis of amounts expected to be paid to the tax authorities or the Balancing Pool of Alberta. The calculation includes consideration of whether it is more likely than not for a contingent liability to be recognized in the financial statements.

Current tax liabilities or assets are measured at the amount expected to be paid to or recovered from the taxation authorities or the Balancing Pool of Alberta for the current and prior periods, using the tax rates that have been enacted or substantively enacted by the end of the reporting period.

Deferred income tax assets and liabilities are recognized for temporary differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, using the tax rates that are expected to apply in the period in which the deferred tax asset or liability is expected to be realized or settled, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred tax asset is recognized for all deductible temporary differences to the extent that it is probable that taxable profit will be available against which the deductible temporary difference can be utilized, with the exception that the deferred tax asset arises from the initial recognition of assets or liabilities in a transaction (other than in a business combination) that affects neither accounting income nor taxable income.

A deferred tax liability is recognized for all taxable temporary differences, unless the deferred tax liability arises from the initial recognition of goodwill, or the initial recognition of other assets or liabilities in a transaction (other than in a business combination) that affects neither accounting income nor taxable income.

The carrying amount of deferred tax assets are reviewed at the end of each reporting period and are reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow the benefit of part or all of that deferred tax asset to be realized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable profits will allow the deferred tax asset to be recovered.

The Corporation recognizes deferred tax liabilities for the taxable temporary differences associated with investments in subsidiaries, and interests in joint arrangements, unless the Corporation is able to control the timing of the reversal of the temporary difference and it is probable the temporary difference will not reverse in the foreseeable future. The Corporation recognizes deferred tax assets for the deductible temporary differences arising from investments in subsidiaries, and interests in joint arrangements only under the circumstances where the temporary differences are expected to reverse in the foreseeable future and there is sufficient taxable income available against which the temporary differences can be utilized. Unrecognized deferred tax assets are reassessed at each reporting date and are recognized to the extent that it has become probable that future taxable profits will allow the deferred tax asset to be recovered.

Deferred tax assets and liabilities are offset when there is a legally enforceable right to set off current tax assets against current tax liabilities and when they relate to income taxes levied by the same taxation authority and the Corporation and its subsidiaries intend to settle their current tax assets and liabilities on a net basis.

5. ACCOUNTING PRONOUNCEMENTS NOT YET ADOPTED

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

IFRS 9 (July 2014) *Financial Instruments*

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

IFRS 15 *Revenue from Contracts with Customers*

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

IFRS 16 *Leases*

The new leases standard requires companies to bring most leases on-balance sheet from 2019. The standard is effective January 1, 2019. Early application is permitted for companies that also apply IFRS 15 Revenue from Contracts with Customers. The Corporation is currently assessing the impact of adopting this standard.

6. SEGMENT INFORMATION

The Corporation operates in two segments representing separately managed business units, each of which offers different products and services. The Corporation uses a shared service allocation model to allocate costs between segments.

ENMAX ENERGY

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

ENMAX POWER

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

SEGMENTED TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT BALANCES

As at *(millions of dollars)*	December 31, 2015	December 31, 2014	January 1, 2014
ENMAX Energy	2,861.5	2,988.1	2,741.6
ENMAX Power	2,087.7	1,938.9	1,756.0
Corporate and eliminations	214.4	107.5	135.9
Total Assets	5,163.6	5,034.5	4,633.5
Regulatory Deferral Account Debit Balances	34.5	66.6	83.7
Total Assets and Regulatory Deferral Account Debit Balances	5,198.1	5,101.1	4,717.2

Year ended December 31, 2015 *(millions of dollars)*	ENMAX Energy	ENMAX Power	Corporate & Intersegment Eliminations	Adjusted Consolidated Totals	Movement in Regulatory Deferral Account	Consolidated Totals
REVENUE						
Electricity	2,147.2	99.6	(329.9)	1,916.9	0.8	1,917.7
Natural gas	359.3	-	(0.8)	358.5	-	358.5
Transmission and distribution	-	501.4	-	501.4	42.9	544.3
Local access fees	-	113.3	-	113.3	-	113.3
Other revenue	27.2	124.1	9.0	160.3	(28.4)	131.9
TOTAL REVENUE	2,533.7	838.4	(321.7)	3,050.4	15.3	3,065.7
OPERATING EXPENSES						
Electricity and fuel purchases	1,763.1	78.5	(328.4)	1,513.2	0.2	1,513.4
Natural gas and delivery	311.0	-	-	311.0	-	311.0
Transmission and distribution	-	230.5	-	230.5	1.3	231.8
Local access fees and grid charges	-	113.3	-	113.3	-	113.3
Depreciation and amortization	136.1	82.6	10.1	228.8	-	228.8
Impairment	146.7	-	-	146.7	-	146.7
Other expenses	194.5	241.6	(5.2)	430.9	(29.3)	401.6
TOTAL OPERATING EXPENSES	2,551.4	746.5	(323.5)	2,974.4	(27.8)	2,946.6
OPERATING PROFIT (LOSS)	(17.7)	91.9	1.8	76.0	43.1	119.1
Finance charges	159.7	37.7	(128.7)	68.7	-	68.7
NET EARNINGS (LOSS) BEFORE TAX	(177.4)	54.2	130.5	7.3	43.1	50.4
Current income tax recovery				(17.2)	-	(17.2)
Deferred income tax recovery				(24.2)	-	(24.2)
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL BALANCES				48.7	43.1	91.8
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	(43.1)	(43.1)
NET EARNINGS				48.7	-	48.7

Year ended December 31, 2014 *(millions of dollars)*	ENMAX Energy	ENMAX Power	Corporate & Intersegment Eliminations	Adjusted Consolidated Totals	Movement in Regulatory Deferral Account	Consolidated Totals
REVENUE						
Electricity	2,389.4	139.3	(376.0)	2,152.7	0.4	2,153.1
Natural gas	542.6	-	(1.0)	541.6	-	541.6
Transmission and distribution	-	504.4	-	504.4	(5.6)	498.8
Local access fees	-	131.3	-	131.3	-	131.3
Other revenue	23.7	126.6	5.7	156.0	(23.8)	132.2
TOTAL REVENUE	2,955.7	901.6	(371.3)	3,486.0	(29.0)	3,457.0
OPERATING EXPENSES						
Electricity and fuel purchases	2,023.9	117.1	(374.4)	1,766.6	-	1,766.6
Natural gas and delivery	508.0	-	-	508.0	-	508.0
Transmission and distribution	-	230.9	-	230.9	(24.0)	206.9
Local access fees and grid charges	-	131.3	-	131.3	-	131.3
Depreciation and amortization	100.7	73.5	3.9	178.1	-	178.1
Impairment	11.7	-	-	11.7	-	11.7
Other expenses	201.8	249.6	(29.3)	422.1	(22.7)	399.4
TOTAL OPERATING EXPENSES	2,846.1	802.4	(399.8)	3,248.7	(46.7)	3,202.0
OPERATING PROFIT	109.6	99.2	28.5	237.3	17.7	255.0
Finance charges	161.1	32.2	(146.0)	47.3	-	47.3
NET EARNINGS (LOSS) BEFORE TAX	(51.5)	67.0	174.5	190.0	17.7	207.7
Current income tax expense				9.9	-	9.9
Deferred income tax recovery				(4.0)	-	(4.0)
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL BALANCES				184.1	17.7	201.8
NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCES				-	(17.7)	(17.7)
NET EARNINGS				184.1	-	184.1

7. FINANCIAL INSTRUMENTS, HEDGES AND RISK MANAGEMENT

RISK ANALYSIS AND CONTROL

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

Sensitivity analysis on market risks

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

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

Certain assumptions have been made in arriving at the sensitivity analysis. These assumptions are as follows:

- The same fair value methodologies have been used as were used to obtain actual fair values in the fair values section of this note.
- Changes in the fair value of derivative instruments that are effective cash flow hedges are recorded in other comprehensive income (OCI).
- Changes in the fair value of derivative instruments that are not designated as hedges, that are fair value hedges or that are ineffective cash flow hedges are recorded in earnings.
- Foreign currency balances, principal and notional amounts are based on amounts as at December 31, 2015 and 2014.
- Interest rate sensitivities are based on Canadian Dealer Offered Rate.

SENSITIVITIES OF MARKET RISKS

Year ended December 31

(millions of dollars)	**2015**		**2014**	
	Earnings	**OCI**	**Earnings**	**OCI**
Interest rates increase 100 basis points (1% pure rate change)	**–**	**–**	–	–
Canadian dollar strengthens compared with the U.S. dollar by 10%	**+1.1**	**–**	-14.6	–
Canadian dollar weakens compared with the U.S. dollar by 10%	**-1.1**	**–**	+14.6	–
Forward price of natural gas increases by 10%	**+9.5**	**+7.3**	+1.9	+14.7
Forward price of natural gas decreases by 10%	**-9.5**	**-7.3**	-1.9	-14.7
Forward price of electricity increases by 10%	**–**	**+32.4**	–	-5.5
Forward price of electricity decreases by 10%	**–**	**-32.4**	–	+5.5

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

FOREIGN EXCHANGE AND INTEREST RATE RISK

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

The Corporation is not exposed to significant interest rate risk and volatility as a result of the issuance of fixed-rate long-term debt. The fair value of the Corporation’s long-term debt and any associated interest rate hedging instruments change as interest rates change, assuming all other variables remain constant.

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

CREDIT RISK

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

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

FINANCIAL ASSETS

As at *(millions of dollars)*	December 31, 2015	December 31, 2014	January 1, 2014
Cash and cash equivalents (a)	**143.7**	16.7	80.6
Accounts receivable (b)	**504.7**	542.8	583.6
Current portion of financial assets (c)	**34.6**	53.6	26.6
Financial assets (c)	**40.7**	14.5	24.3
Restricted cash (Note 10)	**-**	-	8.4
Long-term accounts receivable (b)	**2.7**	7.3	9.2

(a) Cash and Cash Equivalents

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

(b) Current and Long-Term Accounts Receivable

The majority of the Corporation's accounts receivable are exposed to credit risk. Exposure to credit risk occurs through competitive electricity and natural gas supply activities that serve residential, commercial and industrial customers. The risk represents the loss that may be incurred due to the non-payment of a customer's accounts receivable balance, as well as the loss that may be incurred from the resale of energy previously allocated to serve the customer.

Charges to earnings as a result of credit losses for the Corporation for the year ended December 31, 2015, totalled $7.3 million (2014—$18.5 million). Management monitors credit risk exposure and has implemented measures to mitigate losses. In specific situations, this includes, but is not limited to, a reduction of credit limits, requests for additional collateral or restrictions on new transaction terms.

AGING ANALYSIS OF TRADE RECEIVABLES PAST DUE

As at *(millions of dollars)*	December 31, 2015	December 31, 2014	January 1, 2014
1-30 days past due	**13.0**	16.7	31.6
31-60 days past due	**3.1**	4.7	3.4
61 days or more past due	**14.7**	13.1	10.0
Total past due	**30.8**	34.5	45.0

CHANGES IN THE ALLOWANCE FOR DOUBTFUL ACCOUNTS

As at *(millions of dollars)*	December 31, 2015	December 31, 2014	January 1, 2014
Provision at the beginning of the year	**19.1**	7.8	6.7
Increase to allowance	**7.3**	18.5	6.8
Recoveries and write-offs	**(15.1)**	(7.2)	(5.7)
Provision at end of the year	**11.3**	19.1	7.8

The remainder of the accounts receivable balance outstanding at December 31, 2015, consists of current trade receivables and unbilled revenue accruals. No provision has been recorded due to the minimal credit risk at the statement of financial position date.

(c) Current and Non-Current Financial Assets

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

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

Additionally, if a counterparty were to default and the Corporation were to liquidate all contracts with that entity, the credit loss would include the loss in value of mark-to-market contracts, the amount owed for settled transactions and unbilled deliveries and additional payments, if any, that would have to be made to settle unrealized losses on accrual contracts. The majority of counterparties enabled for wholesale transactions are rated investment grade (BBB- or higher) by recognized rating agencies.

LIQUIDITY RISK

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they fall due. The Corporation's approach to managing liquidity risk is to ensure that it always has sufficient cash and credit facilities (see Note 15) to meet its obligations when due.

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

CONTRACTUAL MATURITIES OF NON-DERIVATIVE FINANCIAL LIABILITIES

As at *(millions of dollars)*	**December 31, 2015**	**December 31, 2014**
Less than 1 year (includes accounts payable)	**539.5**	601.8
1–3 years	**569.7**	263.3
3–5 years	**211.1**	499.8
More than 5 years	**1,415.8**	1,025.8

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

CONTRACTUAL MATURITIES OF DERIVATIVE FINANCIAL LIABILITIES

As at *(millions of dollars)*	December 31, 2015	December 31, 2014
Less than 1 year	**61.8**	95.8
1–3 years	**36.5**	15.3
3–5 years	**12.2**	4.9
More than 5 years	**4.4**	3.1

VALUATION OF DERIVATIVE ASSETS AND LIABILITIES

Financial derivative instruments are recorded on the statement of financial position at fair value. As at December 31 the fair values hedge contracts were as follows:

As at *(millions of dollars)*	December 31, 2015		December 31, 2014		January 1, 2014	
	Hedge Instruments	Non-Hedge Derivatives	Hedge Instruments	Non-Hedge Derivatives	Hedge Instruments	Non-Hedge Derivatives
Assets						
Current	**26.9**	**7.7**	41.7	11.9	19.7	6.9
Non-current	**38.7**	**2.0**	14.0	0.5	16.8	7.5
Liabilities						
Current	**49.3**	**12.5**	71.5	24.3	19.6	9.4
Non-current	**45.0**	**8.1**	23.3	-	22.8	25.1

Cash flow hedges are used to manage the variability of cash flows resulting from the purchase and sale of electricity and natural gas, and foreign exchange exposure. For cash flow hedges, changes in the fair value of the effective portion of the hedging derivative are accumulated in OCI and recognized in net earnings during the periods when the variability in cash flows of the hedged item is realized. During the year ended December 31, 2015, there was no impact recognized in electricity and fuel purchases (2014–$9.1 million losses) as a reflection of the ineffectiveness of the relevant hedges. Gains and losses on cash flow hedges are reclassified immediately to net earnings when the hedged item is sold or terminated early or when a hedged anticipated transaction is no longer likely to occur. During 2014, there was $11.2 million impact to earnings related to the interest rate swap hedge that was terminated upon repayment of Calgary Energy Centre (CEC) non-recourse term financing on March 17, 2014.

The Corporation estimates that, of the $23.8 million of losses reported in accumulated OCI as at December 31, 2015, losses of $22.4 million are expected to be realized within the next 12 months, which are expected to be partially offset by long-term gains at market prices in effect at the time of settlement.

Non-hedge derivatives are classified at fair value through profit and loss and recognized at fair market value with changes in fair market value being recorded in Other Expenses. In the year ended December 31, 2015, there were gains of $1.2 million (2014–$8.0 million gain) recorded in net earnings.

FAIR VALUE

Fair value of financial instruments and derivatives is determined by reference to quoted bid or asking price, as appropriate, in active markets at reporting dates. In the absence of an active market, the Corporation determines fair value by using valuation techniques that refer to observable market data or estimated market prices. Fair values determined using valuation models require the use of assumptions about the amount and timing of estimated future cash flows and discount rates. In making these assumptions, the Corporation gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level I) and the lowest priority to unobservable inputs (Level III), as applicable.

Level Determination and Classifications

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

Level I

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

Level II

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

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

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

Level III

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

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

FAIR VALUES OF THE CORPORATION'S DERIVATIVES

As at December 31, 2015 (millions of dollars)	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs (LEVEL II)	Significant Unobservable Inputs [1] (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	**4.3**	**45.5**	**25.4**	**75.2**
Foreign currency forward contracts	-	**0.1**	-	**0.1**
Financial assets total	**4.3**	**45.6**	**25.4**	**75.3**
Financial liabilities measured at fair value:				
Energy trading forward contracts	**(8.7)**	**(87.5)**	**(14.4)**	**(110.6)**
Foreign currency forward contracts	-	**(4.3)**	-	**(4.3)**
Financial liabilities total	**(8.7)**	**(91.8)**	**(14.4)**	**(114.9)**
Net derivative assets (liabilities)	**(4.4)**	**(46.2)**	**11.0**	**(39.6)**

[1] Market-observable data are not available. Fair values are determined using valuation techniques.

As at December 31, 2014 (millions of dollars)	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs (LEVEL II)	Significant Unobservable Inputs [1] (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	7.3	47.7	9.2	64.2
Foreign currency forward contracts	-	3.9	-	3.9
Financial assets total	7.3	51.6	9.2	68.1
Financial liabilities measured at fair value:				
Energy trading forward contracts	(7.2)	(111.8)	-	(119.0)
Foreign currency forward contracts	-	(0.1)	-	(0.1)
Financial liabilities total	(7.2)	(111.9)	-	(119.1)
Net derivative assets (liabilities)	0.1	(60.3)	9.2	(51.0)

[1] Market-observable data are not available. Fair values are determined using valuation techniques.

As at January 1, 2014 (millions of dollars)	Quoted Prices in Active Markets (LEVEL I)	Significant Other Observable Inputs (LEVEL II)	Significant Unobservable Inputs [1] (LEVEL III)	TOTAL
Financial assets measured at fair value:				
Energy trading forward contracts	-	25.6	11.1	36.7
Foreign currency forward contracts	-	3.3	-	3.3
Interest rate swap	-	10.9	-	10.9
Financial assets total	-	39.8	11.1	50.9
Financial liabilities measured at fair value:				
Energy trading forward contracts	-	(41.4)	-	(41.4)
Foreign currency forward contracts	-	(35.5)	-	(35.5)
Financial liabilities total	-	(76.9)	-	(76.9)
Net derivative assets (liabilities)	-	(37.1)	11.1	(26.0)

[1] Market-observable data are not available. Fair values are determined using valuation techniques.

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

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

(millions of dollars)	Hedges
Net derivative assets as at January 1, 2014	11.1
Changes attributable to:	
Commodity price changes	0.7
New contracts entered	0.1
Transfers in/out of Level III	(2.7)
Net derivative assets as at December 31, 2014	9.2
Changes attributable to:	
Commodity price changes	(0.2)
New contracts entered	5.2
Transfers in/out of Level III	(3.2)
Net derivative assets as at December 31, 2015	**11.0**
Total change in fair value included in OCI	(1.8)
Total change in fair value included in pre-tax earnings	–

NON-DERIVATIVE FINANCIAL ASSETS AND LIABILITIES

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

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

CARRYING AMOUNTS AND FAIR VALUES OF LONG-TERM DEBT

As at *(millions of dollars)*	December 31, 2015		December 31, 2014		January 1, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt [1] consisting of:						
Debentures, with remaining terms of						
Less than 5 years	**62.8**	**64.6**	63.2	65.8	34.0	35.4
5–10 years	**76.7**	**83.5**	85.8	93.7	122.4	132.4
10–15 years	**31.1**	**36.0**	21.8	25.4	14.4	16.1
15–20 years	**387.1**	**450.4**	269.7	316.5	187.1	205.6
20–25 years	**653.4**	**683.3**	648.3	690.8	557.6	571.6
Private debentures						
Series 1 (6.15%)	**298.9**	**333.2**	298.5	339.8	298.2	338.8
Series 3 (3.81%)	**198.6**	**206.6**	198.5	201.5	-	-
Non-recourse Kettles Hill Wind Farm (Kettles) term financing	-	-	19.9	21.6	220.5	207.2
Promissory note	**4.2**	**4.5**	4.6	4.8	4.8	4.9
	1,712.8	**1,862.1**	1,610.3	1,759.9	1,439.0	1,512.0

[1] Includes current portion of $66.2 million (December 31, 2014–$62.6 million). Maturity dates range from June 2016 to June 2040.

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

Financial Assets and Financial Liabilities Subject to Offsetting

Information about the Corporation's financial assets and liabilities that are subject to enforceable master netting arrangements or similar agreements is as follows:

As at *(millions of dollars)*	December 31, 2015		December 31, 2014	
	Accounts receivable	Accounts payable and accrued liabilities	Accounts receivable	Accounts payable and accrued liabilities
Gross amounts recognized	**5.5**	**(73.1)**	-	(104.6)
Gross amounts set-off	**(4.9)**	**33.2**	-	44.1
Net amounts as presented in the Consolidated Statement of Financial Position	**0.6**	**(39.9)**	-	(60.5)

8. INCOME TAXES

Year ended December 31 *(millions of dollars)*	2015	2014
Current income tax (recovery) expense		
(Recovery) expense for current year	**(3.6)**	8.8
Adjustment in respect of prior years	**(17.2)**	(0.2)
Non-deductible interest	**3.6**	1.3
Total current income tax (recovery) expense	**(17.2)**	9.9
Deferred income tax (recovery) expense		
Origination and reversal of temporary differences	**(49.0)**	(18.3)
Adjustment in respect of prior years	**17.6**	0.4
Other	**7.2**	13.9
Total deferred income tax recovery	**(24.2)**	(4.0)
Total income tax (recovery) expense	**(41.4)**	5.9

The reconciliation of Statutory and effective income tax expense (recovery)	2015	2014
Net earnings before tax	**50.4**	207.7
Income not subject to tax	**(247.2)**	(296.8)
	(196.8)	(89.1)
Federal and provincial tax rates [(1)]	**26.0%**	25.0%
Expected income tax expense	**(51.1)**	(22.2)
Non-deductible expense	**1.8**	5.6
Adjustment for deferred tax reversal and other estimate revisions	**7.9**	22.5
Total income tax (recovery) expense	**(41.4)**	5.9

[(1)] Alberta has increased the corporate general income tax rate from 10% to 12%, effective July 01, 2015. The Corporation has tax year end at December 31, 2015. Therefore, the two tax rates are pro-rated based on the number of days in the Corporation's taxation year that are before July 1, 2015 and after June 30, 2015. The pro-rated Alberta corporate tax income tax rate is 11%. Combined with 15% federal corporate income tax rate, the statutory tax rate for 2015 is 26%.

The changes in deferred income tax assets and liabilities during the years ended December 31, 2015 and 2014 were as follows:

	December 31, 2014	Recognized in net income	Recognized in other comprehensive income	December 31, 2015
Deferred income tax assets				
Power purchase arrangement	50.7	33.4	-	**84.1**
Property, plant and equipment	(57.0)	(10.1)	-	**(67.1)**
Eligible capital expenditure	6.1	-	-	**6.1**
Losses carried forward	50.9	14.2	-	**65.1**
Unrealized derivatives	4.0	(2.2)	-	**1.8**
Other comprehensive income	3.5	-	(2.5)	**1.0**
Other	-	2.9	-	**2.9**
	58.2	38.2	(2.5)	**93.9**
Deferred income tax liabilities				
Power purchase arrangement	-	-	-	**-**
Property, plant and equipment	96.3	73.3	-	**169.6**
Eligible capital expenditure	-	(3.1)	-	**(3.1)**
Losses carried forward	(24.0)	3.5	-	**(20.5)**
Unrealized derivatives	0.9	(2.0)	-	**(1.1)**
Other comprehensive income	(0.1)	-	-	**(0.1)**
Other	(7.6)	(54.1)	-	**(61.7)**
	65.5	17.6	-	**83.1**
Net deferred tax liability	(7.3)	20.6	(2.5)	**10.8**

	January 1, 2014	Recognized in net income	Recognized in other comprehensive income	December 31, 2014
Deferred income tax assets				
Power purchase arrangement	58.9	(8.2)	-	50.7
Property, plant and equipment	(42.1)	(14.9)	-	(57.0)
Eligible capital expenditure	6.1	-	-	6.1
Losses carried forward	45.4	5.5	-	50.9
Unrealized derivatives	2.5	1.5	-	4.0
Other comprehensive income	(4.1)	-	7.6	3.5
Other	0.1	(0.1)	-	-
	66.8	(16.2)	7.6	58.2
Deferred income tax liabilities				
Power purchase arrangement	-	-	-	-
Property, plant and equipment	106.8	(10.5)	-	96.3
Eligible capital expenditure	-	-	-	-
Losses carried forward	(13.1)	(10.9)	-	(24.0)
Unrealized derivatives	(2.6)	3.5	-	0.9
Other comprehensive income	(2.8)	-	2.7	(0.1)
Other	(6.6)	(1.0)	-	(7.6)
	81.7	(18.9)	2.7	65.5
Net deferred income tax liability	(14.9)	2.7	4.9	(7.3)

The Corporation has the following tax losses carry-forward and deductible temporary differences for which no deferred tax assets have been recognized:

	2015	2014
Non-capital losses	**4.8**	4.5
Property, plant and equipment	**52.2**	48.4
Contingent liabilities	**22.1**	18.7
	79.1	71.6

The changes in income taxes receivable and income taxes payable during the years ended December 31, 2015 and 2014 were as follows:

	December 31, 2014	Prior period adjustments	Instalment and refund	Current year provision	Other	December 31, 2015
Income taxes receivable	96.8	17.2	1.9	3.5	(0.6)	**118.8**
Income taxes payable	(0.6)	-	-	-	0.6	**-**
Net position	96.2	17.2	1.9	3.5	-	**118.8**

	January 1, 2014	Prior period adjustments	Instalment and refund	Current year provision	Other	December 31, 2014
Income taxes receivable	96.9	0.2	7.9	(8.0)	(0.2)	96.8
Income taxes payable	-	-	-	(0.8)	0.2	(0.6)
Net position	96.9	0.2	7.9	(8.8)	-	96.2

As at December 31, 2015, the Corporation has non-capital loss carry-forwards that can be used to offset taxes in future years. These non-capital loss carry-forwards expire as follows:

NON-CAPITAL LOSS CARRY FORWARD

(millions of dollars)	2015
2027	1.8
2028	19.6
2029	5.8
2030	6.5
2031	1.7
2032	6.6
2033	1.3
2034	39.5
2035	122.3

9. REGULATORY DEFERRAL BALANCES

NATURE AND ECONOMIC EFFECT OF RATE REGULATION

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

With respect to ENMAX Distribution, the Corporation filed an application with the AUC on December 18, 2015, requesting approval of its 2015–2017 performance-based regulation (PBR) application. In its application, the Corporation is proposing that distribution rates are adjusted on an annual basis by a rate of inflation (I factor) less an offset (X factor). The Corporation is also seeking a $3.0 million adjustment to account for lower than forecast actual billing determinants (energy, sites and demand) in 2015 and 2016 relative to volumes experienced in 2014. An AUC decision on the Corporation's PBR application is expected by early 2017. With respect to Transmission, the Corporation is preparing to file a 2016–2017 Cost of Service (CoS) application to establish the rates to be paid by the Alberta Electric System Operator (AESO) to the Corporation for the use of the Corporation's transmission facilities.

Regulated rate base for the Division is the aggregate of the AUC approved investment in PPE and intangible assets, less unamortized contributions and total accumulated amortization by customers plus an allowance for working capital.

The AUC approves the allocation of capital of the Division between debt and equity components. The equity ratio to total debt and equity capital was approved as 36.00 per cent and 40.00 per cent for Transmission and Distribution respectively for 2013 to 2015. On April 30, 2015, the AUC issued a letter to all utilities initiating the 2016–2017 Generic Cost of Capital proceeding. In this proceeding, the Commission will approve a return on equity (ROE) value and deemed capital structures for regulated utilities in Alberta for the years 2016 and 2017. An oral hearing is scheduled to commence in Edmonton on May 31, 2016, and a final AUC decision is expected by the end of 2016.

For the year ended December 31, 2014, the Division was subject to a CoS framework for both Distribution and Transmission.

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 debit and credit balances:

As at (millions of dollars)	January 1, 2014	Balances Arising in the Year[1]	Recovery (Reversal)[2]	December 31, 2014	Balances Arising in the Year[1]	Recovery (Reversal)[2]	December 31, 2015	Expected Recovery/Reversal Period (months)
Accounts receivable (a)	41.5	101.1	(124.1)	18.5	120.5	(119.2)	**19.8**	2 Mo
Un-eliminated inter-company profit on underground residential development (b)	-	1.5	-	1.5	0.5	-	**2.0**	
Other regulatory debits (c)	42.2	22.2	(17.8)	46.6	4.1	(38.0)	**12.7**	12 Mo
Total regulatory deferral account debit balances	83.7	124.8	(141.9)	66.6	125.1	(157.2)	**34.5**	

As at (millions of dollars)	January 1, 2014	Balances Arising in the Year[1]	Recovery (Reversal)[2]	December 31, 2014	Balances Arising in the Year[1]	Recovery (Reversal)[2]	December 31, 2015	Expected Recovery/ Reversal Period (months)
Other regulatory credits (d)	1.9	1.4	(0.8)	2.5	13.7	(2.7)	**13.5**	12 Mo
Total regulatory deferral account credit balances	1.9	1.4	(0.8)	2.5	13.7	(2.7)	**13.5**	

[1] "Balances arising in the year" column consists of new additions to regulatory deferral debits and credit balances.
[2] "Recovery/reversal" column consists of amounts collected/refunded through rate riders or transactions reversing existing regulatory balances.

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

(a) Accounts receivable

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

(b) Inter-company profit on underground residential development

A subsidiary of the Corporation performs construction work for the regulated operations of ENMAX Power at a profit. Such profit is deemed for regulatory purposes to be realized to the extent that the transfer price is recognized for rate-making purposes by the regulator and included in the capital cost of distribution assets. In the absence of rate regulation and the interim standard, IFRS would require that intercompany profits be eliminated upon consolidation.

(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. Timing of the decision on collection of these items can result in significant fluctuation in balances from year to year.

(d) Other regulatory credits

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

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

10. OTHER ASSETS AND LIABILITIES

As at *(millions of dollars)*	**December 31, 2015**	**December 31, 2014**	**January 1, 2014**
Other current assets			
Prepaid expenses	**13.0**	9.8	10.1
Deferred asset	**0.3**	-	0.4
Other	**30.9**	17.1	2.9
	44.2	26.9	13.4
Other long-term assets			
Prepaid expenses	**3.8**	4.8	3.6
Restricted cash	**-**	-	8.4
Long-term accounts receivable	**2.7**	7.3	9.2
Deferred asset	**4.1**	-	-
Other	**10.6**	8.1	7.6
	21.2	20.2	28.8
Other current liabilities			
Capital lease	**0.6**	0.5	0.1
Deposits	**31.7**	27.9	18.6
Other	**7.4**	1.8	1.4
	39.7	30.2	20.1
Other long-term liabilities			
Capital lease	**5.6**	5.1	4.6
Other	**11.2**	11.6	10.6
	16.8	16.7	15.2

11. BUSINESS COMBINATIONS

Cavalier Power Station

On September 16, 2014, the Corporation acquired Encana Power and Processing ULC's 100.00 per cent interest in the assets of the Cavalier Power Station (Cavalier) for $169.2 million. The Corporation acquired Cavalier to increase its generation capacity. Cavalier is a natural-gas-fuelled generation plant located southeast of Strathmore, Alberta. The results of operations for these assets have been included in the consolidated financial statements since that date.

ASSETS ACQUIRED AND LIABILITIES RECOGNIZED AT THE DATE OF ACQUISITION *(millions of dollars)*	**2014**
Property, plant and equipment	173.7
Asset retirement obligation	(4.5)
Fair value of net assets acquired	169.2

PURCHASE CONSIDERATION *(millions of dollars)*	**2014**
Cash	169.2
Other consideration	-
	169.2

The acquisition of Cavalier has resulted in revenues of $5.0 million and overall net loss of $2.9 million in 2014 for the period from September 16, 2014 to December 31, 2014. Acquisition-related costs amounting to $1.9 million were expensed in 2014.

12. PROPERTY, PLANT AND EQUIPMENT

	Transmission, Distribution and Substation Equipment	Generation Facilities and Equipment	Buildings and Site Development	Tools, Systems and Equipment	Land	Capital Spares and Other	Vehicles	Construction in Progress	Government Grants	Total
Cost										
As at January 1, 2014	1,383.1	1,230.0	153.9	77.2	34.4	33.5	24.1	866.3	(20.0)	3,782.5
Additions	-	-	-	-	-	-	-	398.0	-	398.0
Transfers	184.5	2.3	55.2	11.8	2.9	5.7	2.5	(264.9)	-	-
Acquisitions	-	232.3	-	-	-	-	-	-	-	232.3
Disposals	(6.0)	(0.4)	(1.3)	(1.8)	(0.4)	-	(1.7)	-	-	(11.6)
Changes to asset retirement costs	-	22.4	-	-	-	-	-	-	-	22.4
As at December 31, 2014	1,561.6	1,486.6	207.8	87.2	36.9	39.2	24.9	999.4	(20.0)	4,423.6
Additions	-	-	-	-	-	-	-	282.7	-	282.7
Transfers	253.4	903.0	18.8	10.7	0.8	4.4	2.6	(1,193.7)	-	-
Disposals	(16.1)	(0.2)	(1.1)	(1.6)	-	-	(2.5)	-	-	(21.5)
Changes to asset retirement costs	-	4.3	-	-	-	-	-	-	-	4.3
As at December 31, 2015	**1,798.9**	**2,393.7**	**225.5**	**96.3**	**37.7**	**43.6**	**25.0**	**88.4**	**(20.0)**	**4,689.1**
Accumulated Depreciation										
As at January 1, 2014	(2.2)	(383.6)	(24.1)	(48.7)	-	-	(4.0)	-	2.3	(460.3)
Depreciation	(61.9)	(44.2)	(6.9)	(6.8)	-	-	(1.9)	-	0.7	(121.0)
Disposals	6.0	0.1	0.1	1.7	-	-	1.5	-	-	9.4
Impairment	-	(11.3)	-	-	-	-	-	-	-	(11.3)
As at December 31, 2014	(58.1)	(439.0)	(30.9)	(53.8)	-	-	(4.4)	-	3.0	(583.2)
Depreciation	(67.9)	(82.0)	(13.7)	(8.9)	-	-	(2.8)	-	0.7	(174.6)
Disposal	24.5	-	1.1	1.5	-	-	2.5	-	-	29.6
As at December 31, 2015	**(101.5)**	**(521.0)**	**(43.5)**	**(61.2)**	**-**	**-**	**(4.7)**	**-**	**3.7**	**(728.2)**
Net Book Value										
As at January 1, 2014	1,380.9	846.4	129.8	28.5	34.4	33.5	20.1	866.3	(17.7)	3,322.2
As at December 31, 2014	1,503.5	1,047.6	176.9	33.4	36.9	39.2	20.5	999.4	(17.0)	3,840.4
As at December 31, 2015	**1,697.4**	**1,872.7**	**182.0**	**35.1**	**37.7**	**43.6**	**20.3**	**88.4**	**(16.3)**	**3,960.9**

Real property, including land and buildings, with a carrying amount of $219.7 million as at December 31, 2015 (December 31, 2014–$213.8 million), was subject to a right of first refusal to purchase held by The City.

For the year ended December 31, 2015, capitalized borrowing costs amounted to $14.7 million (2014–$49.4 million), with capitalization rates ranging from 4.13 per cent to 5.34 per cent. Interest is capitalized based on the actual costs of debt used to finance the capital construction projects. Interest rates ranged from 0.62 per cent to 6.31 per cent (2014–1.03 per cent to 6.31 per cent).

During the year, the Corporation wrote off a project of $2.3 million in construction in progress. At December 31, 2015, the Corporation performed an impairment test of all of its CGUs (Note 3). No impairment expense was required as a result of these procedures.

13. POWER PURCHASE ARRANGEMENTS

Under the Keephills PPA, which was acquired in 2000 and expires December 2020, the Corporation owns the rights to the physical output of two electrical generating units. Under the Battle River PPA, which was acquired in stages from 2006 to 2010, Battle River 3 and 4 expired at the end of 2013 and Battle River 5 expires in 2020.

In December 2015, the Corporation determined that the Battle River PPA would be unprofitable or more unprofitable in light of low wholesale electricity prices and increased costs under the Alberta Specified Gas Emitters Regulation announced in June 2015. Accordingly, the Corporation exercised its right to terminate the arrangement, effective January 1, 2016. As a result of this decision, the Corporation recorded an impairment on the Battle River 5 PPA of $144.4 million.

	Battle River	Keephills	Total
Cost			
As at January 1, 2014	572.0	256.5	828.5
Additions	-	-	-
Disposals	-	-	-
As at December 31, 2014	572.0	256.5	828.5
Additions	-	0.9	0.9
Disposals	-	-	-
As at December 31, 2015	**572.0**	**257.4**	**829.4**
Accumulated Amortization			
As at January 1, 2014	(373.0)	(180.4)	(553.4)
Amortization	(28.7)	(10.9)	(39.6)
As at December 31, 2014	(401.7)	(191.3)	(593.0)
Amortization	(25.9)	(11.0)	(36.9)
Impairment	(144.4)	-	(144.4)
As at December 31, 2015	**(572.0)**	**(202.3)**	**(774.3)**
Net Book Value			
As at January 1, 2014	199.0	76.1	275.1
As at December 31, 2014	170.3	65.2	235.5
As at December 31, 2015	**-**	**55.1**	**55.1**

14. INTANGIBLE ASSETS

	Computer systems	Renewable energy certificates and water licenses	Customer lists and contracts	Land easements, rights and lease options	Work in progress	Total
Cost						
As at January 1, 2014	263.4	12.4	20.0	3.1	35.6	334.5
Additions	-	-	-	-	30.9	30.9
Transfers	6.8	-	-	-	(6.8)	-
Disposals	(28.7)	-	-	-	-	(28.7)
As at December 31, 2014	241.5	12.4	20.0	3.1	59.7	336.7
Additions	-	-	-	-	34.4	34.4
Transfers	43.0	-	-	30.5	(73.5)	-
Disposals	(18.2)	-	-	-	-	(18.2)
As at December 31, 2015	**266.3**	**12.4**	**20.0**	**33.6**	**20.6**	**352.9**
Accumulated Amortization						
As at January 1, 2014	(191.2)	(7.5)	(17.9)	(2.7)	-	(219.3)
Amortization	(13.1)	(1.6)	(2.1)	(0.1)	-	(16.9)
Disposals	28.7	-	-	-	-	28.7
Impairment	(0.3)	-	-	-	-	(0.3)
As at December 31, 2014	(175.9)	(9.1)	(20.0)	(2.8)	-	(207.8)
Amortization	(14.6)	(1.7)	-	(1.1)	-	(17.4)
Disposals	18.1	-	-	-	-	18.1
As at December 31, 2015	**(172.4)**	**(10.8)**	**(20.0)**	**(3.9)**	**-**	**(207.1)**
Net Book Value						
As at January 1, 2014	72.2	4.9	2.1	0.4	35.6	115.2
As at December 31, 2014	65.6	3.3	-	0.3	59.7	128.9
As at December 31, 2015	**93.9**	**1.6**	**-**	**29.7**	**20.6**	**145.8**

15. SHORT-TERM DEBT

As at *(millions of dollars)*	December 31, 2015		December 31, 2014	
	Available	Used	Available	Used
Unsecured credit facilities				
Bilateral operating facilities	**600.0**	**234.8**	900.0	219.0
Syndicated credit facilities	**250.0**	**-**	250.0	30.0
	850.0	**234.8**	1,150.0	249.0

The Corporation uses unsecured credit facilities to fund general operating requirements and to provide liquidity support for commercial paper and commodity marketing programs.

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

16. LONG-TERM DEBT

As at *(millions of dollars)*	December 31, 2015	Weighted Average Interest Rates	December 31, 2014	Weighted Average Interest Rates	January 1, 2014	Weighted Average Interest Rates
City debentures [1] with remaining terms of:						
Less than 5 years	**62.8**	**2.53%**	63.2	3.41%	34.0	4.20%
5 – 10 years	**76.7**	**4.20%**	85.8	4.30%	122.4	4.39%
10 – 15 years	**31.1**	**4.65%**	21.8	4.85%	14.4	4.85%
15 – 20 years	**387.1**	**4.49%**	269.7	4.61%	187.1	4.57%
20 – 25 years	**653.4**	**3.37%**	648.3	3.68%	557.6	3.93%
Private debenture [1]	**497.5**	**5.21%**	497.0	5.21%	298.2	6.15%
Non-recourse financing	**-**	**-**	19.9	5.86%	220.5	6.45%
Promissory note	**4.2**	**5.00%**	4.6	5.00%	4.8	5.00%
	1,712.8		1,610.3		1,439.0	
Less: current portion	**66.2**		62.6		63.7	
	1,646.6		1,547.7		1,375.3	

[1] Unsecured debentures.

CITY DEBENTURES

Debentures were initially issued by The City on behalf of the CES pursuant to City bylaw authorizations prior to January 1, 1998. Pursuant to the master agreement between the Corporation and The City, the debentures were included in the assumed liabilities upon transfer of substantially all of the assets and liabilities of the CES from The City to the Corporation at January 1, 1998. In accordance with a debt management service level agreement between the Corporation and The City, The City continues to administer the new and existing debentures on behalf of the Corporation.

On June 15, 2015, the Corporation obtained $189.2 million of 5-, 10-, 20- and 25-year unsecured debentures from The City through arrangements with the Alberta Capital Finance Authority (ACFA) (June 2014–$232.1 million in 5-, 10-, 20- and 25-year debentures). Interest on the debentures is compounded semi-annually as follows: $21.8 million, which matures in June 2020, at 1.34 per cent; $3.6 million, maturing in June 2025, at

2.03 per cent; $18.5 million, maturing in June 2035, at 2.77 per cent; and the remaining $145.3 million of the debt, which matures in June 2040, at 2.94 per cent. The funds were used for capital expenditures in ENMAX Power.

The Corporation is required to reimburse The City for all principal repayments and interest payments with respect to the debentures on the same day as The City disburses the payments to ACFA. In addition, the Corporation is required to pay a loan guarantee and administration fee to The City of 0.25 per cent on the average monthly outstanding ACFA debenture balance held by The City on behalf of the Corporation.

PRIVATE DEBENTURES

No private debentures were issued in 2015. In December, 2014, a Series 3 Private Debenture of $200.0 million at 3.81 per cent was issued. The outstanding unsecured private debentures of $300.0 million and $200.0 million at December 31, 2015, bear interest at a rate of 6.15 per cent and 3.81 per cent, respectively, payable semi-annually and mature on June 19, 2018, and December 5, 2024, respectively.

NON-RECOURSE FINANCING

On June 1, 2015, the Corporation paid the outstanding principal of non-recourse Kettles Hills Wind Farm term financing prior to maturity in December 2016. The carrying amount of the debt was $19.9 million.

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

PROMISSORY NOTE

The promissory note was issued in the fourth quarter of 2006 and represents an amortizing loan from the Board of Trustees of Westwind School Division No. 74, acting as agent for the Wind Participation Consortium (WPC), which is comprised of three school divisions. The 20-year note, in the amount of $6.3 million, bears interest at a fixed rate of 5.00 per cent and is repayable in monthly instalments. The Corporation provided a fixed charge over two wind turbines located at Taber, Alberta, as security for the loan. Concurrent with execution of the loan, WPC executed a 20-year electricity services agreement with ENMAX Energy.

PRINCIPAL REPAYMENTS

The required repayments of principal on the long-term debt at December 31, 2015, are as follows:

Required repayments of principal
As at December 31
(millions of dollars)

	2015
Less than 1 year	65.6
1–3 years	433.4
3–5 years	122.4
More than 5 years	1,091.4

17. ASSET RETIREMENT OBLIGATIONS AND OTHER PROVISIONS

	Asset Retirement Obligations	Restructuring	Onerous Contracts	Total
As at January 1, 2014	49.9	-	20.0	69.9
Additions	6.7	-	-	6.7
Utilized in the year	-	-	(1.3)	(1.3)
Accretion expense	1.3	-	-	1.3
Revision in discount rate	22.4	-	-	22.4
As at December 31, 2014	80.3	-	18.7	99.0
Additions	-	11.2	3.3	14.5
Utilized in the year	-	(10.3)	(1.7)	(12.0)
Accretion expense	1.8	-	-	1.8
Revision in discount rate	4.3	-	-	4.3
As at December 31, 2015	**86.4**	**0.9**	**20.3**	**107.6**

Asset Retirement Obligations

The Corporation has estimated the net present value of the decommissioning liabilities associated with ENMAX Energy based on a total undiscounted future liability of $195.1 million (December 31, 2014–$199.3 million) calculated using an inflation rate of 2.00 per cent (December 31, 2014–2.00 per cent). These payments are expected to be made between 2039 and 2071. The Corporation calculated the present value of the obligations using discount rates between 1.92 per cent and 2.15 per cent (December 31, 2014–between 2.20 per cent and 2.33 per cent) to reflect the market assessment of the time value of money.

Restructuring

During 2015, the Corporation restructured its organization structure to enhance its competitiveness and execution of its strategy. Total provisions recorded amounted to $11.2 million of which $10.3 was paid before December 31, 2015.

Onerous contracts

The Corporation recognized onerous liability for certain contracts related to an impaired asset on transition to IFRS (see Note 29).

18. SHARE CAPITAL

(millions of dollars, except share amounts)	Number of Shares	Amount
Authorized:		
Unlimited number of common shares		
Issued and outstanding:		
Balance, January 1, 2014, and December 31, 2014 and 2015:		
Issued on incorporation	1	–
Issued on transfer of net assets from CES *(Note 1)*	1	278.2
Issued on transfer of billing and customer care assets from The City in 2001	1	1.9
Balance, January 1, 2014, and December 31, 2014 and 2015	**3**	**280.1**

19. POST-EMPLOYMENT BENEFITS

The Corporation has a registered pension plan that substantially covers all employees and includes both DB and DC provisions. The DB provisions provide a pension based on years of service and highest average earnings over five consecutive years of employment. DB pension benefits under the registered plan will increase annually by at least 60.00 per cent of the consumer price index for Alberta. Under the DC provisions, the employer provides a base level of contributions, and additional employer contributions are matched based on the participating members' contribution levels and points (age plus service) calculation.

The Corporation also sponsors a supplemental pension plan providing an additional DC or DB pension to members whose benefits are limited by maximum pension rules under the ITA. The supplemental pension plan benefits do not automatically increase. In addition, the Corporation provides employees with post-retirement benefits other than pensions, including extended health benefits beyond those provided by government-sponsored plans, life insurance, Health Care Spending accounts and a lump-sum allowance payable at retirement, up to age 65.

Total cash payments for employee future benefits for the year ended December 31, 2015, consisting of cash contributed by the Corporation under the DB and DC provisions of the registered pension plan and cash payments directly to beneficiaries of the Corporation's unfunded other-benefit plans, were $23.1 million (2014–$21.4 million).

For the year ended December 31, 2015, the total expense for the defined contribution provisions of the plan is $9.9 million (2014–$8.9 million).

The table below outlines the Corporation's post-employment amounts and activity as presented in the consolidated financial statements:

As at (millions of dollars)	December 31, 2015	December 31, 2014	January 1, 2014
Net defined benefit liability for:			
Pension benefit plan	**28.3**	45.0	32.0
Other benefit plan	**11.6**	11.4	11.2
Total post-employment benefits liability	**39.9**	56.4	43.2

For the year ended December 31, (millions of dollars)	2015	2014
Income statement charge included in profit or loss for:		
Pension benefit plan	**12.9**	10.3
Other benefit plan	**1.2**	1.5
	14.1	11.8
Re-measurement losses (gains) recognized in other comprehensive income:		
Pension benefit plan	**(17.4)**	14.4
Other benefit plan	**(0.3)**	(0.6)
	(17.7)	13.8

Information about the DB provisions of the plan, including the supplemental pension plan and the post-retirement non-pension benefit plan, is as follows:

	December 31, 2015		December 31, 2014	
(millions of dollars)	Pension Benefit Plan	Other Benefit Plan	Pension Benefit Plan	Other Benefit Plan
Change in defined benefit obligation:				
Balance, beginning of year	**311.0**	**11.4**	268.1	11.2
Current service cost	**10.9**	**0.9**	8.6	1.0
Interest cost	**11.4**	**0.4**	11.7	0.5
Employee contributions	**3.3**	-	3.1	-
Actuarial losses (gains)	**(11.2)**	**(0.3)**	35.0	(0.6)
Benefits paid	**(20.1)**	**(0.8)**	(15.5)	(0.7)
Defined benefit obligation, end of year	**305.3**	**11.6**	311.0	11.4
Change in plan assets:				
Fair value, beginning of year	**266.0**	-	236.1	-
Interest income	**9.9**	-	10.6	-
Return on plan assets, excluding amounts included in interest expense	**6.2**	-	20.6	-
Employer contributions	**11.5**	-	11.5	0.7
Employee contributions	**3.3**	-	3.1	-
Benefits paid	**(19.1)**	-	(15.5)	(0.7)
Non-investment expenses	**(0.8)**	-	(0.4)	-
Plan assets at fair value, end of year	**277.0**	-	266.0	-
Funded status-plan deficit				
Accrued benefit asset (liability)	**(28.3)**	**(11.6)**	(45.0)	(11.4)

DEFINED BENEFIT COST – STATEMENT OF COMPREHENSIVE INCOME

Years ended December 31		**2015**		**2014**
(millions of dollars)	**Pension Benefit Plan**	**Other Benefit Plan**	**Pension Benefit Plan**	**Other Benefit Plan**
Current service costs	**10.9**	**0.8**	8.6	1.0
Net interest on net benefit liability	**1.5**	**0.4**	1.2	0.5
Admin costs	**0.5**	**-**	0.5	-
Net benefit plan expense	**12.9**	**1.2**	10.3	1.5

DEFINED BENEFIT COST – STATEMENT OF OTHER COMPREHENSIVE INCOME

Years ended December 31		**2015**		**2014**
(millions of dollars)	**Pension Benefit Plan**	**Other Benefit Plan**	**Pension Benefit Plan**	**Other Benefit Plan**
Return on plan assets (greater) less than discount	**(6.2)**	**-**	(20.6)	-
Actuarial (gains) losses				
Experience adjustments	**-**	**(0.3)**	7.6	1.6
Changes in assumptions	**(11.2)**	**-**	27.4	(2.2)
Re-measurement effects recognized (OCI)	**(17.4)**	**(0.3)**	14.4	(0.6)

The defined pension benefits plan's assets are comprised as follows:

As at	**December 31, 2015**				**December 31, 2014**				**January 1, 2014**			
(millions of dollars)	**Quoted**	**Un-quoted**	**Total**	**In %**	**Quoted**	**Un-quoted**	**Total**	**In %**	**Quoted**	**Un-quoted**	**Total**	**In %**
Canadian equity securities			**71.1**	**25.7%**			73.3	27.5%			70.9	30.1%
Small company equity fund	**8.5**	**-**	**8.5**		10.3	-	10.3		7.3	-	7.3	
Canadian equity fund	**62.6**	**-**	**62.6**		63.0	-	63.0		63.6	-	63.6	
Foreign equity securities			**87.9**	**31.7%**			85.1	32.0%			74.0	31.3%
U.S. large company equity fund	**48.3**	**-**	**48.4**		48.1	-	48.1		42.3	-	42.3	
Developed country equity fund	**39.5**	**-**	**39.5**		37.0	-	37.0		31.7	-	31.7	
Fixed-income securities			**104.1**	**37.6%**			106.4	40.0%			87.4	37.0%
Canadian fixed income fund	**5.5**	**-**	**5.5**		7.9	-	7.9		10.8	-	10.8	
Canadian long duration bond fund	**38.6**	**-**	**38.6**		37.1	-	37.1		42.0	-	42.0	
Real return bond fund	**16.7**	**-**	**16.7**		18.2	-	18.2		12.7	-	12.7	
Long duration credit bond fund	**30.3**	**-**	**30.4**		30.6	-	30.6		21.9	-	21.9	
U.S. high yield bond fund	**12.9**	**-**	**12.9**		12.6	-	12.6		-	-	-	
Real estate investments	**11.7**	**-**	**11.7**	**4.2%**	-		-	-			-	-
Cash and cash equivalents	**-**	**1.5**	**1.5**	**0.5%**	-	0.2	0.2	0.1%	-	3.6	3.6	1.5%
Non-investment asset	**-**	**0.7**	**0.7**	**0.3%**		1.0	1.0	0.4%	-	0.2	0.2	0.1%
Total plan assets			**277.0**	**100%**			266.0	100.0%			236.1	100.0%

(a) Assumptions

The significant weighted-average actuarial assumptions adopted in measuring the Corporation's defined benefit obligations and net benefit plan expense are as follows:

Year ended December 31,	2015		2014	
	Pension Benefit Plan	Other Benefit Plan	Pension Benefit Plan	Other Benefit Plan
Defined benefit obligation:				
Discount rate	**4.00%**	**3.50%**	3.75%	3.50%
Inflation rate	**2.25%**	**n/a**	2.25%	n/a
Rate of compensation increase	**3.25%**	**3.25%**	3.25%	3.25%
Health care cost trend rate for next year	**n/a**	**7.00%**	n/a	7.00%
Decreasing gradually to 5% in the year	**n/a**	**2021**	n/a	2021
Average life expectancy[1]				
Male	**21.5**	**n/a**	21.5	n/a
Female	**23.9**	**n/a**	23.9	n/a
Net benefit plan expense:				
Discount rate	**3.75%**	**3.50%**	4.50%	4.25%
Inflation rate	**2.25%**	**n/a**	2.25%	n/a
Rate of compensation increase	**3.25%**	**3.25%**	3.25%	3.25%
Health care cost trend rate for next year	**n/a**	**7.00%**	n/a	8.00%
Decreasing gradually to 5% in the year	**n/a**	**2021**	n/a	2020

[1] The average life expectancy for a 65 year old based on the mortality tables used for year-end disclosures.

The per capita cost of covered dental benefits was assumed to increase by 4.50 per cent per year (2014 – 4.50 per cent).

The sensitivity of the defined benefit obligation (DBO) to changes in assumptions is set out below. The effects on each plan of a change in an assumption are weighted proportionately to the total plan obligations to determine the total impact for each assumption presented.

SENSITIVITIES OF ASSUMPTIONS

Impact on Pension Benefit Plan DBO	**December 31, 2015**		
	Change in assumption	**Increase**	**Decrease**
Discount rate	**1%**	**(35.3)**	**44.2**
Rate of compensation increase	**1%**	**7.3**	**(6.4)**
Inflation rate	**1%**	**25.5**	**(22.2)**
Life expectancy	**1 year**	**6.1**	**n/a**

SENSITIVITIES OF ASSUMPTIONS

Impact on Pension Benefit Plan DBO	**December 31, 2014**		
	Change in assumption	**Increase**	**Decrease**
Discount rate	1%	(36.0)	45.1
Rate of compensation increase	1%	7.5	(6.6)
Inflation rate	1%	26.1	(22.6)
Life expectancy	1 year	6.2	n/a

SENSITIVITIES OF ASSUMPTIONS

Impact on Other Benefit Plan DBO

	December 31, 2015		
	Change in assumption	**Increase**	**Decrease**
Discount rate	**1%**	**(0.9)**	**1.1**
Rate of compensation increase	**1%**	**0.4**	**(0.3)**
Health care cost trend rate	**1%**	**0.3**	**(0.3)**
Life expectancy	**1 year**	**(0.1)**	**n/a**

SENSITIVITIES OF ASSUMPTIONS

Impact on Other Benefit Plan DBO

	December 31, 2014		
	Change in assumption	**Increase**	**Decrease**
Discount rate	1%	(0.9)	1.1
Rate of compensation increase	1%	0.4	(0.3)
Health care cost trend rate	1%	0.3	(0.3)
Life expectancy	1 year	(0.1)	n/a

Each sensitivity analysis disclosed in this note is based on changing one assumption while holding all other assumptions constant. In practice, this is unlikely to occur, and changes in some of the assumptions may be correlated. When calculating the sensitivity of the defined benefit obligation to variations in significant actuarial assumptions, the same method (present value of the DBO calculated with the projected unit credit method at the end of the reporting period) has been applied as for calculating the liability recognized in the statement of financial position.

(b) Maturity analysis

An actuarial valuation was performed as of December 31, 2013. Based on the 2013 pension valuation, the aggregate solvency deficit in the Corporation's funded pension plans amounted to $27.9 million. The Corporation will make special payments for past service of $3.6 million annually to fund the defined pension benefits plans' deficit over 10 years. Current agreed service contributions is 11.82 per cent of pensionable salaries and continue to be made in the normal course. Total expected contributions to post-employment benefit plans for the year ending December 31, 2016 (including the past service contributions) are $10.1 million.

The weighted average duration of the defined benefit obligation for the pension benefit plan and the other benefit plan is 13.6 years and 8.4 years respectively (2014: 13.9 years and 8.5 years).

Expected maturity analysis of undiscounted pension and other benefit plans:

	Less than 1 year	**1 -3 years**	**3 – 5**	**More than 5 years**	**Total**
Defined pension benefit plan	15.9	33.9	35.5	91.5	176.8
Other benefit plans	0.9	2.0	2.1	5.1	10.1
At December 31, 2015	**16.8**	**35.9**	**37.6**	**96.6**	**186.9**
Pension benefit plan	17.3	32.9	34.0	90.9	175.1
Other benefit plans	1.2	1.9	2.1	5.3	10.5
At December 31, 2014	**18.5**	**34.8**	**36.1**	**96.2**	**185.6**

(c) Risk assessment

Funding risk

The primary risk associated with the DB pension for the plan sponsor is the risk that investment asset growth and contribution rates will not be sufficient to cover pending funding obligations, resulting in unfunded liabilities.

Alberta registered plans are required to file funding valuations on a triennial basis with a few exceptions. If the going concern funded status is less than 85.00 per cent, a plan may be required to file an annual valuation. Based on the 2013 pension valuation, the DB Provisions are 101.00 per cent funded on a going-concern basis and 89.00 per cent on a solvency basis. The funding ratio is monitored on an ongoing basis. The next valuation will be completed for December 31, 2016.

Investment risk

The Corporation makes investment decisions for its funded plan based on an asset-liability matching analysis reflecting the results of its aforementioned funding valuations. The Corporation attempts to achieve investment returns in excess of its liabilities by setting an asset-allocation target based on risks and returns. This targeted asset allocation is recorded ENMAX Pension Plan Statement of Investment Policies and Procedures (SIPP). The plan's asset portfolio is regularly monitored to ensure compliance to the SIPP, as well as its performance as compared to a liability benchmark intended to approximate the growth in the plan's future obligations. Given the likely significant shortening of the liability structure with the passage of time, the continuing appropriateness of the plan's asset allocation is evaluated at least once every three years.

20. DEFERRED REVENUE

Revenues arising from the recognition of contributions in aid of construction (CIAC) was $12.7 million for the year ended December 31, 2015 (2014–$13.6 million).

21. ACCUMULATED OTHER COMPREHENSIVE LOSS

As at *(millions of dollars)*	**December 31, 2015**	**December 31, 2014**	**January 1, 2014**
Net unrealized (losses) on available-for-sale financial assets	**(0.1)**		(0.1)
Net unrealized (losses) on derivatives designated as cash flow hedges, including deferred income tax recovery of $0.9 (December 31, 2014–recovery of $3.5 million)	**(27.8)**	(35.6)	(7.3)
Net actuarial gains (losses) on defined benefit plans, including deferred income tax recovery of $0.2 (December 31, 2014–recovery of $0.2 million)	**4.1**	(13.6)	
Accumulated other comprehensive losses, including deferred income tax recovery of $1.1 million (December 31, 2014–recovery of $3.7 million)	**(23.8)**	(49.2)	(7.4)

22. OTHER REVENUE AND EXPENSES

OTHER REVENUE

Year ended December 31 *(millions of dollars)*	2015	2014
Contractual service	**99.6**	98.1
Interest and penalty revenue	**10.6**	9.6
Amortization of CIAC	**12.7**	13.6
Miscellaneous	**9.0**	10.9
	131.9	132.2

OTHER EXPENSES

Year ended December 31 *(millions of dollars)*	2015	2014
Salaries and wages	**236.9**	231.6
Materials and supplies	**20.1**	23.7
Goods and services	**78.6**	73.1
Administrative and office expenses	**7.3**	18.5
Building expense	**46.1**	70.7
Restructuring (Note 17)	**11.2**	-
Vehicles and Other	**20.9**	(6.4)
Foreign exchange gains	**(19.5)**	(11.8)
	401.6	399.4

23. JOINT ARRANGEMENTS

Significant joint operations included in the consolidated financial statements at December 31, 2015 are listed below.

Significant Joint Operations	Operating Jurisdiction	Ownership Percent	Principal Activity
McBride Lake Wind Facility	Canada	50%	Wind turbine generating facility
Shepard Energy Centre	Canada	50%	Gas-fired generating facility
Balzac Power Station	Canada	50%	Gas-fired generating facility
Genesee 4 and 5	Canada	50%	Gas-fired generating project

24. DIVIDEND

On March 19, 2015, the Corporation declared a dividend of $56.0 million to The City (2014–$60.0 million). The dividend was paid in equal quarterly instalments during 2015.

25. FINANCE CHARGES

Year ended December 31 *(millions of dollars)*	2015	2014
Accretion expense	**1.8**	1.3
Interest expense - pension	**1.8**	1.7
Interest on long term debt	**76.6**	67.1
Short term interest and other financing charges	**3.2**	4.0
Interest rate swaps settlement	**-**	22.6
Less capitalized borrowing costs	**(14.7)**	(49.4)
	68.7	47.3

26. CHANGE IN NON-CASH WORKING CAPITAL

As at *(millions of dollars)*	2015	2014
Accounts receivable	**38.1**	40.8
Regulatory deferral account debit balance	**32.1**	17.1
Other assets	**(18.6)**	(4.9)
Accounts payable and accrued liabilities	**(28.1)**	(16.8)
Regulatory deferral account credit balances	**11.0**	0.6
Other liabilities	**9.6**	11.6
Provisions	**2.5**	(1.3)
Change related to operating activities	**46.6**	47.1

27. RELATED-PARTY TRANSACTIONS

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

Statements of earnings

Year ended December 31 *(millions of dollars)*	2015	2014
Revenue (1)	**117.1**	127.2
Local access fees and other expenses (2)	**120.1**	137.9

(1) The significant components include contract sales of electricity, construction of infrastructure, provision of non-regulated power distribution services, and billing and customer care services relating to The City's utilities departments.
(2) This cost is passed through the Corporation directly to transmission and distribution customers.

Statements of financial position

Year ended December 31 *(millions of dollars)*	2015	2014
Accounts receivable	**22.8**	35.7
Other long-term assets	**1.9**	2.5
PPE (1)	**3.9**	4.1
Accounts payable and accrued liabilities	**9.7**	12.0
Long-term debt (2)	**1,211.1**	1,088.8
Other long-term liabilities (3)	**4.4**	4.6

(1) Assets under the lease.
(2) Interest and principal payments for the year ended December 31, 2015 were $45.2 million (2014 - $41.3 million) and $66.9 million (2014 - $58.8 million) respectively. In addition, the Corporation paid a management fee of $2.9 million to The City for the year ended December 31, 2015, (2014 - $2.6 million).
(3) Finance lease obligation.

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

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

Compensation of key management

The Corporation's key management personnel are members of the Board of Directors and the executive management team considered to have the authority and responsibility for planning, directing and controlling the activities at the Corporation.

The total compensation and remuneration paid by the Corporation and its subsidiary companies to the key management personnel is presented below:

Year ended December 31 *(millions of dollars)*	**2015**	**2014**
Salaries and other short-term employee benefits[1]	**8.6**	6.7
Other long-term benefits	**3.0**	5.3
Retirement and post-employment benefits	**0.6**	0.6
	12.2	12.6

[1] Includes severance payment of $2.0 million

28. COMMITMENTS AND CONTINGENCIES

Property, plant and equipment

The Corporation is committed to major capital expenditures over the next five years and thereafter, with minimum annual payments (including cancellation costs) as follows:

Major capital commitments over the next five years

(millions of dollars)	
2016	2.2
2017	1.9
2018	1.9
2019	1.9
2020	1.9
Thereafter	41.5

Obligations under other agreements

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

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

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

The aggregated minimum payments under these arrangements over the next five years are as follows:

Aggregate payments under other agreements

(millions of dollars)	
2016	98.3
2017	84.8
2018	62.1
2019	12.9
2020	6.3
Thereafter	50.9

REGULATORY

The Corporation, along with other electrical transmission and distribution utilities in the province of Alberta, is subject to regulatory reviews and decisions. The impact of the reviews and decisions is reflected in the consolidated financial statements when the amount can be reasonably estimated.

LEGAL CLAIMS

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

POWER PURCHASE ARRANGEMENTS

During the year, the facilities covered under PPAs were subject to outages, operational issues and other disputes. In December, the Corporation notified the Balancing Pool of the decision to terminate the Battle River PPA effective January 1, 2016. The Balancing Pool, the PPA owner and the Corporation may differ in opinion as to who should bear the costs arising from these events. Although there can be no assurance that these disputes will be resolved in the Corporation's favor, the Corporation does not believe that the outcome of these disputes will have a material adverse effect on its financial position.

INCOME TAX

Alberta Finance, Tax and Revenue Administration is responsible for assessing the income tax returns filed under the PILOT regulation of the EUA, which became effective January 1, 2001.

Certain ENMAX entities experienced a change in tax status with the introduction of PILOT regulation. This resulted in all PILOT-related assets (primarily the PPA-owned assets at that time) being deemed to be disposed of and immediately reacquired at fair market value for tax purposes effective December 31, 2000. Alberta Finance disagrees with ENMAX's fair market value for tax purposes and we have received reassessments and communications in respect of the taxation years 2001 through 2011 accordingly. We do not agree with the reassessments and have commenced the necessary steps to defend our positions through the formal appeals and litigation process.

When Alberta Finance conducted its 2006 audit of ENMAX Energy Corporation and ENMAX PSA Corporation, it disagreed with the interest expense deducted on the PILOT returns. ENMAX Corporation loaned money to its affiliates ENMAX Energy Corporation in 2004 and ENMAX PSA Corporation in 2006 and 2007. We have received reassessments and communications from Alberta Finance in respect of the taxation years from 2006 through 2011. ENMAX does not agree with the reassessments and has taken necessary steps to defend our positions through the formal appeals and litigation process.

The Corporation regularly reviews the potential for adverse outcomes in respect of tax matters and believes it has adequate provisions for these tax matters. The determination of the income tax provision is an inherently complex process, requiring management to interpret continually changing regulations and to make certain judgments. Although there can be no assurance that the disputes will be resolved in the Corporation's favor, the Corporation does not believe that the outcome of these disputes will have a material adverse effect on its financial position. In accordance with IFRS, the Corporation has disclosed the general nature of its tax disputes with Alberta Finance. Any additional details required by IFRS have not been disclosed because it can potentially prejudice the Corporation's position during the ongoing litigation process.

ENVIRONMENTAL

Provincial regulations aimed at reducing the levels of greenhouse gas (GHG) emissions took effect July 2007, which were subsequently updated in June 2015 for the years 2016—17. Due to the change of law provisions in ENMAX Energy's PPAs and tolling agreements, ENMAX Energy is exposed to the associated compliance costs. The recent Alberta Government policy announcement (Climate Leadership Plan) made in November 2015 would further subject the Keephills PPA to significant GHG compliance costs for the years 2018—2020. This policy has not been drafted into legislation and this impact may vary depending on the final tabled legislation. This policy announcement has no material financial impact to the Corporation's fleet of gas fired assets.

For the year ended December 31, 2015, the consolidated financial statements include a charge to earnings in the amount of $15.1 million (2014—$20.2 million) included in costs of electricity services provided, relating to estimated compliance costs under the provincial GHG regulations for ENMAX Energy's interests in coal and natural-gas-fuelled generation facilities through its PPAs and owned assets. Compliance payments are due to the Province of Alberta, directly or via plant owners, by June 30 of the year following the compliance year. ENMAX Energy has taken steps, including acquiring qualified offset credits from both its wind-generation assets and purchases on the wholesale market, to mitigate impacts of the GHG regulations.

LETTERS OF CREDIT

In the normal course of operations, letters of credit are issued to facilitate the extension of sufficient credit for counterparties having credit exposure to the Corporation or its subsidiaries. As at December 31, 2015, the Corporation had issued letters of credit amounting to $234.8 million (December 31, 2014—$249.0 million).

DIRECTOR/OFFICER INDEMNIFICATIONS

Under its bylaws, the Corporation indemnifies individuals who have acted at the Corporation's request to be a director and/or officer of the Corporation and/or one or more of its direct and indirect subsidiaries, to the extent permitted by law, against any and all damages, liabilities, costs, charges or expenses suffered or incurred by the individuals as a result of their service. The claims covered by such indemnifications are subject to statutory or other legal restrictions and limitation periods. The nature of the indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum potential amount it could be required to pay to beneficiaries of such indemnification agreements. The Corporation has purchased various insurance policies to reduce the risks associated with the indemnification.

OTHER INDEMNIFICATIONS

In the ordinary course of business, the Corporation and its subsidiaries enter into contracts that contain indemnification provisions, such as purchase and sale contracts, service agreements, intellectual property licensing agreements, purchases and sales of assets and equipment, joint venture agreements (JVAs), operating agreements and leasing and land use arrangements. In such contracts, the Corporation may indemnify counterparties to the contracts if certain events occur, such as undisclosed liabilities, changes in financial condition and loss caused by the actions of third parties or as a result of litigation or other claims by third parties. These indemnification provisions will vary based upon the contract. In many cases, there are no pre-determined amounts or limits included in these indemnification provisions, and the occurrence of contingent events that will trigger payment under them is difficult to predict. Therefore, the maximum potential future amount the Corporation could be required to pay cannot be estimated.

29. TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

These consolidated financial statements are the first annual financial statements that comply with IFRS. These consolidated financial statements have been prepared as described in Note 2, including the application of IFRS 1. For all periods up to and including the year ended December 31, 2014, the Corporation prepared its financial statements in accordance with Canadian GAAP.

IFRS 1 requires that comparative financial information be provided. As a result, the first date at which the Corporation began applying IFRS was January 1, 2014 (the transition date). IFRS 1 requires that a first time adopter use the same accounting policies in its opening IFRS statement of financial position and for all subsequent periods presented in its first IFRS financial statements. The adoption of IFRS includes full retrospective application of all IFRS standards which are effective at the end of its first IFRS reporting period, December 31, 2015.

In order to facilitate an effective adoption of IFRS, there are a number of discretionary exemptions as well as mandatory exceptions from retrospective application of a number of IFRS standards.

A. MANDATORY EXCEPTIONS TO RETROSPECTIVE APPLICATION

The mandatory exceptions applied from full retrospective application of IFRS are described below.

i. Hedge accounting

In accordance with IFRS 1, an entity shall not reflect in its opening IFRS statement of financial position a hedging relationship of a type that does not qualify for hedge accounting in accordance with IAS 39 *Financial Instruments: Recognition and Measurement*. If, before the date of transition to IFRSs, an entity had designated a transaction as a hedge but the hedge does not meet the conditions for hedge accounting in IAS 39, the entity shall discontinue hedge accounting. This exception did not result in change in the statements of financial position and total comprehensive income for the Corporation.

ii. Estimates

In accordance with IFRS 1, an entity's estimates under IFRS at the date of transition to IFRS must be consistent with estimates made for the same date under previous GAAP, unless there is objective evidence that those estimates were in error. The Corporation's IFRS estimates as of January 1, 2014 are consistent with its Canadian GAAP estimates for the same date, except to reflect any difference in accounting policies.

iii. Derecognition of financial instruments

In accordance with IFRS 1, a first-time adopter shall apply the requirements within IAS 39 prospectively from the transition date unless it chooses to apply the derecognition guidance retrospectively from a date of its election. The Corporation has elected to apply derecognition of financial instruments prospectively from January 1, 2014, the date of transition. Based on the election, there were no significant adjustments required as a result of derecognition.

B. ELECTED EXEMPTIONS FROM FULL RETROSPECTIVE APPLICATION

i. Business combinations

As permitted under IFRS 1, the Corporation did not retrospectively apply IFRS 3 Business Combinations to past business combinations. Accordingly, the Corporation has not restated business combinations that took place prior to the transition date.

ii. Deemed costs for operations subject to rate regulation

At the date of transition to IFRS, the Corporation has elected to measure the $1,535 million in regulated PPE and $20.1 million in regulated intangible assets as deemed cost. The carrying amount under Canadian GAAP included the effects of rate-regulation as permitted under Canadian GAAP.

iii. Transfer of assets from customers

At transition to IFRS, the Corporation has elected to apply transitional provisions as outlined in IFRIC 18 – *Transfers of assets from customers.* The Corporation has recognized the balance of contributions in aid of construction as deferred revenue and amortized into income on a systematic basis. Under Canadian GAAP, contributions in aid of construction were netted against the cost of PPE.

iv. Leases

IFRS allows an exemption from applying IFRIC 4 – *Determining whether an arrangement contains a lease* at the date of transition to IFRS if the same determination was made at a previous date in accordance with another GAAP. The Corporation has elected to apply this exemption not to reassess historical leases already assessed under Canadian GAAP.

v. Decommissioning liabilities

IFRS 1 provides a first time adopter with a simplified approach to calculate the cost of PPE associated with decommissioning an asset at the transition date. The decommissioning liability must be calculated as follows:

- The liability must be measured in accordance with IAS 37 Provisions, Contingent Liability and Contingent Assets at transition;
- Estimate the amount that would have been included in the cost of the asset when the liability first arose by discounting the liability to that date using its best estimate of historical risk-adjusted discount rates; and
- Calculate the accumulated depreciation on that amount, as at the transition date to IFRS.

The Corporation has elected to calculate the decommissioning liability and associated cost of PPE as of January 1, 2014 using the approach described above.

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

During the finalization of IFRS conversion in 2015, management re-measured the ARO liability as at December 31, 2014 to reflect the change in discount rate that occurred at the end of 2014.

As a result of this restatement, ARO and PPE both increased by $22.4 million in the consolidated statement of financial position and shareholder’s equity at December 31, 2014. The change had nil impact on total comprehensive income and statements of cash flows for the year ended December 31, 2014.

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

I. Reconciliation of consolidated statement of financial position and shareholder's equity at January 1, 2014, the date of transition from Canadian GAAP to IFRS:

January 1, 2014 (*millions of dollars*)		Canadian GAAP	Measurement Adjustments	Reclassification Adjustments	IFRS
ASSETS					
Cash and cash equivalents		80.6	-	-	80.6
Accounts receivable	(4)	665.5	-	(81.9)	583.6
Income taxes receivable		96.9	-	-	96.9
Deferred income tax assets	(1)	8.7	-	(8.7)	-
Current portion of financial assets	(2)(h)	-	(3.0)	29.6	26.6
Other current assets	(2)(a)	42.6	0.4	(29.6)	13.4
		894.3	(2.6)	(90.6)	801.1
Property, plant and equipment	(a)(c)(d)(g)(5)	3,022.6	(26.0)	325.6	3,322.2
Power purchase arrangements	(d) (e)	369.5	(94.4)	-	275.1
Intangible assets	(f)	124.3	(9.1)	-	115.2
Goodwill	(d)	16.0	(16.0)	-	-
Employee future benefits	(b)	22.8	(22.8)	-	-
Deferred income tax assets	(a)(c)(d)(e)(g)(h)(1)	59.0	0.8	7.0	66.8
Financial assets	(h)(2)	-	(2.1)	26.4	24.3
Other long-term assets	(2)(4)	57.0	-	(28.2)	28.8
TOTAL ASSETS		4,565.5	(172.2)	240.2	4,633.5
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	(4)	-		83.7	83.7
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES		4,565.5	(172.2)	323.9	4,717.2
LIABILITIES					
Accounts payable and accrued liabilities	(4)	436.8	-	(1.9)	434.9
Deferred income tax liabilities	(1)	0.5	-	(0.5)	-
Current portion of long-term debt		63.7	-	-	63.7
Current portion of financial liabilities	(3)	-	-	29.0	29.0
Current portion of deferred revenue		5.2	-	-	5.2
Current portion of asset retirement obligations and other provisions	(g)	-	0.9	-	0.9
Other current liabilities	(3)	47.6	1.5	(29.0)	20.1
		553.8	2.4	(2.4)	553.8
Long-term debt		1,375.3	-	-	1,375.3
Deferred income tax liabilities	(a)(c)(1)	100.1	(17.2)	(1.2)	81.7
Post-employment benefits	(b)	-	43.2	-	43.2
Financial liabilities	(3)	-	-	47.9	47.9
Deferred revenue	(5)	4.8	-	325.6	330.4
Other long-term liabilities	(g)(3)	55.9	7.2	(47.9)	15.2
Asset retirement obligations and other provisions	(g)	15.4	53.6	-	69.0
TOTAL LIABILITIES		2,105.3	89.2	322.0	2,516.5
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES	(4)	-	-	1.9	1.9
SHAREHOLDER'S EQUITY					
Share capital		280.1	-	-	280.1
Retained earnings	(a) to (g)	2,186.4	(260.3)	-	1,926.1
Accumulated other comprehensive income (loss)	(h)	(6.3)	(1.1)	-	(7.4)
		2,460.2	(261.4)	-	2,198.8
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY		4,565.5	(172.2)	323.9	4,717.2

II. Reconciliation of consolidated statement of financial position and shareholder's equity at December 31, 2014, from Canadian GAAP to IFRS:

December 31, 2014 *(millions of dollars)*	Notes	Canadian GAAP	Measurement Adjustments	Reclassifincation Adjustments	IFRS
ASSETS					
Cash and cash equivalents		16.7	-	-	16.7
Accounts receivable	(4)	606.5	-	(63.7)	542.8
Income taxes receivable		96.8	-	-	96.8
Deferred income tax assets	(1)	16.6	-	(16.6)	-
Current portion of financial assets	(2)	-	(5.3)	58.9	53.6
Other current assets	(2)	85.8	-	(58.9)	26.9
		822.4	(5.3)	(80.3)	736.8
Property, plant and equipment	(a)(c)(d)(g)(4)(5)	3,483.7	2.7	354.0	3,840.4
Power purchase arrangements	(d) (e)	316.7	(81.2)	-	235.5
Intangible assets	(f)	136.7	(7.8)	-	128.9
Employee future benefits	(b)	21.6	(21.6)	-	-
Deferred income tax assets	(a)(c)(d)(e)(g)(h)(1)	23.8	17.8	16.6	58.2
Financial assets	(h)(2)	-	(0.6)	15.1	14.5
Other long-term assets	(2)(4)	36.7	-	(16.5)	20.2
TOTAL ASSETS		4,841.6	(96.0)	288.9	5,034.5
REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES	(4)	-	-	66.6	66.6
TOTAL ASSETS AND REGULATORY DEFERRAL ACCOUNT DEBIT BALANCES		4,841.6	(96.0)	355.5	5,101.1
LIABILITIES					
Short-term debt		27.3	-	-	27.3
Accounts payable and accrued liabilities	(4)	422.3	-	(2.5)	419.8
Income taxes payable		0.6	-	-	0.6
Deferred income tax liabilities	(1)	0.9		(0.9)	-
Current portion of long-term debt		62.6	-		62.6
Current portion of financial liabilities	(3)	-	-	95.8	95.8
Current portion of deferred revenue		12.1	-	-	12.1
Current portion of asset retirement obligations and other provisions	(g)	-	0.9	-	0.9
Other current liabilities	(3)	123.7	2.3	(95.8)	30.2
		649.5	3.2	(3.4)	649.3
Long-term debt		1,547.7	-	-	1,547.7
Deferred income tax liabilities	(a)(c)(1)	61.4	3.2	0.9	65.5
Post-employment benefits	(b)	-	56.4	-	56.4
Financial liabilities	(3)	-	-	23.3	23.3
Deferred revenue	(5)	5.0	-	355.5	360.5
Other long-term liabilities	(g)(3)	30.2	9.8	(23.3)	16.7
Asset retirement obligations and other provisions	(g)	20.1	78.0	-	98.1
TOTAL LIABILITIES		2,313.9	150.6	353.0	2,817.5
REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES	(4)	-	-	2.5	2.5
SHAREHOLDER'S EQUITY					
Share capital		280.1	-	-	280.1
Retained earnings	(a) to (g)	2,281.4	(231.2)	-	2,050.2
Accumulated other comprehensive income	(h)	(33.8)	(15.4)	-	(49.2)
		2,527.7	(246.6)	-	2,281.1
TOTAL LIABILITIES, REGULATORY DEFERRAL ACCOUNT CREDIT BALANCES AND SHAREHOLDER'S EQUITY		4,841.6	(96.0)	355.5	5,101.1

III. Reconciliation of total comprehensive income reported under Canadian GAAP to IFRS for the year ended December 31, 2014:

Year ended December 31, 2014 *(millions of dollars)*		Canadian GAAP	IFRS Adjustments	IFRS
REVENUE				
Electricity	(4)	2,152.7	0.4	2,153.1
Natural gas		541.6	-	541.6
Transmission and distribution	(4)	380.3	118.5	498.8
Local assess fees		131.3	-	131.3
Other revenue	(4)(5)	142.4	(10.2)	132.2
TOTAL REVENUE		3,348.3	108.7	3,457.0
OPERATING EXPENSES				
Electricity and fuel purchases		1,766.6	-	1,766.6
Natural gas and delivery		508.0	-	508.0
Transmission and distribution	(4)	106.8	100.1	206.9
Local access fees and grid charges		131.3	-	131.3
Depreciation and amortization	(a)(d)(e)(f)(g)(5)	174.2	3.9	178.1
Impairment	(c)	34.4	(22.7)	11.7
Other expense	(a)(g)(4)	425.6	(26.2)	399.4
TOTAL OPERATING EXPENSES		3,146.9	55.1	3,202.0
OPERATING PROFIT		201.4	53.6	255.0
Finance charges	(b)(g)	44.3	3.0	47.3
NET EARNINGS BEFORE TAX		157.1	50.6	207.7
Current Income tax expense		9.9	-	9.9
Deferred income tax expense (recovery)	(a)(c)(d)(e)(g)(h)	(7.8)	3.8	(4.0)
NET EARNINGS BEFORE NET MOVEMENT IN REGULATORY DEFERRAL ACCOUNT BALANCE		155.0	46.8	201.8
NET MOVEMENT REGULATORY DEFERRAL ACOUNT BALANCES	(4)	-	(17.7)	(17.7)
NET EARNINGS		155.0	29.1	184.1
OTHER COMPREHENSIVE INCOME (LOSS), NET OF INCOME TAX				
Re-measurement gains (losses) retirement benefits, net of deferred income tax benefit of $0.2		-	(13.6)	(13.6)
Unrealized gains (losses) on derivatives designated as cash flow hedges; includes deferred income tax expense of $2.5	(h)	(2.5)	(0.7)	(3.2)
Realized losses (gains) on derivatives designated as cash flow hedges in prior periods transferred to net earnings in the current year; includes deferred income tax expense of $7.3		(25.0)	-	(25.0)
Other comprehensive income (loss), net of income tax		(27.5)	(14.3)	(41.8)
TOTAL COMPREHENSIVE INCOME		127.5	14.8	142.3

EXPLANATION OF THE MEASUREMENT ADJUSTMENTS IN THE TABLES ABOVE

(a) Property, plant and equipment (PPE)

(i) PPE (major overhaul and inspection costs)

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

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

IMPACT ON THE CORPORATION

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

As a result of this change, depreciation expense was higher by $3.5 million for the year ended December 31, 2014.

(ii) PPE (derecognition)

Canadian GAAP does not specifically require the carrying amount of parts that are replaced to be derecognized.

IFRS specifically requires derecognition of the replaced parts regardless of whether the replaced parts had been depreciated separately.

IMPACT ON THE CORPORATION

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

As a result of this change, depreciation expense was lower by $0.3 million for the year ended December 31, 2014.

(iii) PPE (pre-operating costs)

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

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

IMPACT ON THE CORPORATION

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

As a result of this change, depreciation expense was higher by $0.1 million for the year ended December 31, 2014.

(b) Post-retirement benefits

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

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

IMPACT ON THE CORPORATION

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

As a result of this change, service cost decreased by $1.8 million for the year ended December 31, 2014. Also, net interest of $1.6 million for the year ended December 31, 2014, has been re-classed from Other Expenses to Finance Charges.

(c) Business combination

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

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

IMPACT ON THE CORPORATION

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

Subsequent to the negative goodwill reversal, an impairment charge was determined on the assets (see Note d). As a result of this change, depreciation expense was higher by $5.8 million for the year ended December 31, 2014.

(d) Impairment testing

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

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

IMPACT ON THE CORPORATION

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

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

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

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

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

As a result of this change, depreciation and amortization expenses were lower by $5.5 million for the year ended December 31, 2014.

(e) PPA amortization

Under Canadian GAAP, PPAs are amortized on a straight line basis over the contract term. Under IFRS, PPAs can be amortized based on available capacity per PPA unit over the term of the PPA.

IMPACT ON THE CORPORATION

On transition, accumulated amortization increased by $91.0 million with a tax impact of $22.7 million. The net decrease to retained earnings was $68.3 million. As a result of this change, amortization expense was lower by $12.8 million for the year ended December 31, 2014.

(f) Website

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

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

IMPACT ON THE CORPORATION

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

As a result of this change, amortization expense was lower by $1.0 million for the year ended December 31, 2014.

(g) Provisions

(i) Provisions (asset retirement obligations)

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

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

IMPACT ON THE CORPORATION

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

The unwinding of the discount is now included in finance charges. Accretion expense in the amount of $0.8 million has been re-classed from Other Expenses to Finance Charges for the year ended December 31, 2014.

In addition, depreciation expense was $0.5 million higher and finance charges were $0.5 million higher for the year ended December 31, 2014.

ARO liability and ARO asset both increased by $22.4 million as a result of re-measuring the ARO at December 31, 2014.

(ii) Provisions (constructive obligation)

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

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

IMPACT ON THE CORPORATION

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

As a result of this change, bonus expense was higher by $2.9 million for year ended December 31, 2014.

(iii) Provisions (onerous contracts obligation)

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

IMPACT ON THE CORPORATION

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

As a result of this change, operating expenses were lower by $1.3 million for the year ended December 31, 2014.

(h) Financial instruments

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

Under IFRS, the documentation requirement does not exist.

IMPACT ON THE CORPORATION

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

As a result of this change, OCI was higher by $0.7 million for the year ended December 31, 2014.

EXPLANATION OF THE RECLASSIFICATION ADJUSTMENTS IN THE TABLES ABOVE

1. Reclassification adjustment (1) reclassifies the current portion of deferred income tax asset (liability) from current to long term in accordance with IAS 1, Presentation of Financial Statements.

2. IAS 1 requires the statement of financial position to include separate line items for financial assets that are included in other current assets and other assets under Canadian GAAP.

3. IAS 1 requires the statement of financial position to include separate line items for financial liabilities that are included in other current liabilities and other liabilities under Canadian GAAP.

4. IFRS 14 requires separate disclosure in the statement of financial position for (a) the total of all regulatory deferral account debit balances and (b) the total of all regulatory deferral account credit balances. IFRS 14 also requires presenting the net movement in all regulatory deferral account balances on a separate line in the statement of earnings.

5. IFRIC 18 requires contributions from customers for PPE be classified as deferred revenues, versus netted against PPE under previous GAAP.

ADJUSTMENTS TO THE STATEMENT OF CASH FLOWS

As a result of the transition from Canadian GAAP to IFRS, the proceeds from contributions from customers are included as cash flow in operating activities. Previously, these proceeds were netted against PPE purchases within cash flow from investing activities.

30. SUBSEQUENT EVENT

On March 16, 2016, the Corporation declared a dividend of $47.0 million payable to The City in quarterly instalments in 2016.

GLOSSARY OF TERMS

ACFA	Alberta Capital Finance Authority
ACTA	Alberta Corporate Tax Act
AcSB	Accounting Standards Board of Canada
AESO	Alberta Electric System Operator
AFRC	Audit Finance and Risk Committee
AUC	Alberta Utilities Commission
BLIERs	Base level industrial emissions Requirements
Board	ENMAX's Board of Directors
CEC	Calgary Energy Centre
Corporation	ENMAX Corporation and its subsidiaries
CoS	Cost of Service
CPLP	Capital Power LP
CES	Calgary Electric System
CCEMA	Change and Emissions Management Amendment
CIAC	Contributions in aid of construction
Crossfield	Crossfield Energy Centre
DB	Defined benefit
DBO	Defined benefit obligation
DBRS	Dominion Bond Rating Services
DC	Defined contribution
DDEC	Downtown District Energy Centre
EBIT	Earnings before interest and income taxes
EBITDA	Earnings before interest, income tax and depreciation
EPSP	Energy price setting plan
EMS	Environmental management system
ENMAX	ENMAX Corporation and its subsidiaries
Envision	ENMAX Envision Inc.
ERM	Enterprise risk management
ESA	Energy services agreements
EUA	Alberta Electric Utilities Act
FVTPL	Financial Assets & Liabilities at your value through profit or loss
FBR	Formula-based rates
GAAP	Generally Accepted Accounting Principles
GCOC	Generic Cost of Capital
GHG	Greenhouse gas
GJ	Gigajoule
GWh	Gigawatt hour
IASB	International Accounting Standards Board
IBEW	International Brotherhood of Electrical Workers
ICFR	Internal control over financial reporting
IDC	Interest during construction
IFRS	International Financial Reporting Standard
ITA	Income Tax Act (Canada)
JVA	Joint venture agreement
Kettles	Kettles Hill Wind Farm
LTSA	Long-Term service agreement
McBride	McBride Lake Wind Farm
MD&A	Management's Discussion and Analysis
MSA	Market surveillance administrator
MW	Megawatt
MWh	Megawatt hour
OCI	Other comprehensive income
OM&A	Operations, maintenance and administration
PBR	Performance based rates
PILOT	Payment in lieu of tax
PPA	Power purchase arrangement
PPE	Property, plant and equipment
RMC	Risk Management Committee
ROE	Return on equity
RRO	Regulated rate option
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
Shepard	Shepard Energy Centre
Taber	Taber Wind Farm
The City	The City of Calgary
TJ	Terajoule
TransAlta	TransAlta Corporation
URD	Underground residential development

ADDITIONAL INFORMATION

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

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