Management's Discussion and Analysis

Alectra Inc.

Year ended December 31, 2019

GLOSSARY of ACRONYMS and ABBREVIATIONS

The following acronyms and abbreviations are used in this document.

AES	Alectra Energy Solutions Inc.
AESI	Alectra Energy Services Inc.
AFFO	Adjusted Funds from Operations
APA	Arrears Payment Agreements
APSI	Alectra Power Services Inc.
AUC	Alectra Utilities Corporation
CDM	Conservation & Demand Management
CP	Commercial Paper
DBRS	Dominion Bond Rating Service
DSC	Distribution System Code
DSP	Distribution System Plan
EBITDA	Earnings before interest, taxes, depreciation and amortization
ERM	Enterprise Risk Management
ERP	Enterprise Resource Planning
FFO	Funds from Operations
GHESI	Guelph Hydro Electric System Inc.
GMHI	Guelph Municipal Holding Inc.
ICM	Incremental Capital Module
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
IR	Incentive Rate
kWh	Kilowatt Hours
LDC	Local Distribution Company
MD&A	Management Discussion and Analysis
MIFRS	Modified International Financial Reporting Standards
OEB	Ontario Energy Board
OEBA	Ontario Energy Board Act
OEFC	Ontario Electricity Finance Corporation
OREC	Ontario Rebate for Electricity Customers
RRFE	Renewed Regulatory Framework for Electricity Distributors
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
UA	Util-Assist Inc.
WMS	Wholesale Market Service

FORWARD LOOKING STATEMENTS AND INFORMATION

Alectra Inc. ("the Corporation")'s oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the business and the industry in which the Corporation operates, and include beliefs and assumptions made by the management of the Corporation. Such statements include, but are not limited to:

- Statements about strategy, including strategic objectives;
- Statements regarding CDM programs and targets;
- The estimated impact of changes in the forecasted long-term Government of Canada bond yield (used in determining the regulated rate of return) on the results of operations;
- Statements related to economic conditions;
- Statements regarding liquidity and capital resources and operational requirements;
- Statements regarding credit facilities and other sources of corporate liquidity;
- Expectations regarding financing activities;
- Statements regarding ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives and their completion dates;
- Expectations regarding the recoverability of large capital expenditures;
- Statements regarding expected future capital and development expenditures, the timing of these expenditures and investment plans;
- Statements regarding contractual obligations and other commercial commitments;
- Statements related to the OEB;
- Statements regarding future post-retirement benefit contributions, and actuarial valuations; and
- Statements related to the outlook and our approach to distribution rationalization.

Words such as “expect”, “anticipate”, “intend”, “attempt”, “may”, “plan”, “will”, “believe”, “seek”, “estimate”, “goal”, “aim”, “target”, and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions, risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward- looking statements. The Corporation does not intend, and disclaims any obligation, to update any forward-looking statements, except as required by law. These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following:

- No unforeseen changes in the legislative and operating framework for Ontario’s electricity market;
- Decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications;
- No delays in obtaining required approvals;
- No unforeseen changes in rate orders or rate structures;
- A stable regulatory environment;
- No changes in environmental regulation; and
- No significant event occurring outside the ordinary course of business.

These assumptions are based on information currently available to the Corporation, including information obtained from third- party sources. Actual results may differ materially from those predicted by such forward-looking statements.

While the Corporation does not know what impact any of these differences may have, the business, results of operations, financial condition and credit stability may be materially adversely affected thereby.

Readers are cautioned that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section “Risk Factors” in this MD&A. Readers should review this section in detail. In addition, the Corporation cautions the reader that information provided in this MD&A regarding the Corporation’s outlook on certain matters, including future expenditures, is provided in order to give context to the nature of some of the Corporation’s future plans and may not be appropriate for other purposes.

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INTRODUCTION

The following discussion and analysis of the consolidated financial condition and results of operations of the Corporation should be read together with its consolidated financial statements and accompanying notes for the year ended December 31, 2019 (the “Consolidated Financial Statements”) and 2018.

The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board and in effect at December 31, 2019. All dollar amounts in the tables are in millions of Canadian dollars, which are presented in whole numbers.

CORPORATE OVERVIEW

Alectra Inc. is indirectly owned through holding companies by eight shareholders: the City of Barrie; the City of Hamilton; the City of Markham; the City of Mississauga; the City of St. Catharines; the City of Vaughan; the City of Guelph and BPC Energy Corporation. Alectra Inc. was created in 2017 by (“Merger Transaction”): i) the amalgamation of the former entities: PowerStream Holdings Inc.; Enersource Holdings Inc.; and Horizon Holdings Inc. ; ii) the acquisition of Hydro One Brampton Networks Inc. ("Brampton Hydro") and its subsequent amalgamation with Alectra Utilities Corporation ("AUC"). In 2019 Guelph Hydro Electric System Inc ("GHESI") was acquired and subsequently amalgamated with AUC.

Alectra Inc. is an investment holding company that owns 100% of the common shares of each of: AUC; Alectra Energy Solutions Inc. ("AES"); and Horizon Solar Corporation ("Horizon Solar"). The Corporation also indirectly wholly owns Alectra Energy Services Inc. ("AESI") which, in turn, has wholly owned subsidiaries Alectra Power Services Inc. ("APSI") and Util-Assist Inc. ("UA"). On January 1, 2019, the Corporation issued shares to GMHI in consideration for all the issued and outstanding shares of GHESI.

Alectra Utilities Corporation

AUC provides electricity distribution to approximately one million customers and is the second largest municipally-owned LDC in North America by customers.

In addition to its electricity distribution business, AUC also has a non-regulated commercial rooftop solar photovoltaic generation business ("Solar PV Business") under which it develops, constructs, owns, finances and operates rooftop photovoltaic generation equipment ("Solar PV Property"). The electricity generated by the Solar PV Business is sold to the IESO under its Feed- In-Tariff long term power purchase agreements.

Alectra Energy Solutions Inc.

AES is an Ontario-based company that provides customers with non-regulated energy solutions through the use of innovative technologies. AES owns 100% of the common equity of each of AESI and APSI.

AESI provides wholesale metering and sub-metering services for condominium and commercial properties. AESI owns 100% of the shares of UA. UA provides consulting services with respect to Advanced Metering Infrastructure integration, customer information systems implementation, sync operation services, conservation initiatives, an outage management call centre under the name PowerAssist, and other smart grid applications.

APSI provides street lighting services including design, construction, and maintenance.

in millions of Canadian dollars

Credit Rating

The Corporation's credit ratings are as follows:

	DBRS			S&P Global Ratings		
	Date Confirmed	Credit Rating	Trend	Date Confirmed	Credit Rating	Outlook
Issuer rating	July 4, 2019	A	Stable	April 26, 2019	A	Stable
Senior unsecured debentures	April 4, 2019	A	Stable	April 26, 2019	A	Stable
Short term (Commercial Paper)	July 4, 2019	R1(low)	Stable			

Vision & Strategic Intent

The vision of the Corporation is to be Canada's leading electricity distribution and integrated energy solutions provider, creating a future where people, businesses and communities will benefit from energy's full potential. For further details on the values and the mission of the Corporation, please review the 2019 Annual Sustainability Report on the Corporation's website at: https://alectrautilities.com/about-alectra/investor-relations/

INDUSTRY REGULATION

The *Ontario Energy Board Act, 1998 (Ontario) ("OEBA")* conferred on the OEB powers and responsibilities to regulate the electricity industry in Ontario. These powers and responsibilities include: approving or fixing rates for the transmission and distribution of electricity; providing continued rate protection for rural and remote residential electricity consumers; and ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to LDCs, such as the Corporation, which may include, among other things: record keeping; regulatory accounting principles; separation of accounts for distinct business; and filing and process requirements for rate setting purposes.

AUC is regulated by the OEB. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that differ from IFRS. The regulatory accounting treatments of the OEB require the recognition of regulatory assets and liabilities which do not meet the definition of an asset or liability under IFRS. Under IFRS, 14, *Regulatory Deferral Accounts,* entities are permitted to recognize regulatory assets and liabilities in its financial statements provided that i) the entity is a first - time adopter of IFRS and ii) the pre- IFRS statements of the entity recognized regulatory assets and liabilities. Prior to the 2017 Merger Transaction, the legacy entities adopted IFRS in 2011 and did not recognize regulatory assets and liabilities in its financial statements. As a result, the Corporation did not meet the requirements for adoption of IFRS 14, and as such, regulatory assets and liabilities have not been recorded in its Consolidated Financial Statements.

Rate Setting

The electricity distribution rates and other regulated charges of the Corporation are determined in a manner that provides shareholders of the Corporation with opportunity to earn a regulated Maximum Allowable Return on Equity on the amount of shareholders' equity supporting the business of electricity distribution, which is also determined by regulation.

The rate-making policies of the OEB are guided by its statutory objectives under the OEBA that include, among other matters, to support the cost-effective planning and operation of the electricity distribution network and to provide an appropriate alignment between a sustainable, financially viable electricity sector and the expectations of customers for reliable service at a reasonable price.

The OEB regulates the electricity distribution rates charged by LDCs, such as AUC, through periodic rate applications to the OEB and its ongoing monitoring and reporting requirements. At present, LDCs may apply to the OEB for electricity distribution rates under options specified in its *Report of the Board - A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach ("RRFE")*. The three rate-setting methods available to LDCs under the RRFE are: Price Cap Incentive Rate-setting ("Price Cap IR"); Custom Incentive Rate-setting ("Custom IR"); or Annual Incentive Rate-setting Index ("Annual IR"). These methods are described in more detail in the Consolidated Financial Statements.

The Incremental Capital Module ("ICM") is available to distributors under the Price Cap IR method. It is intended to address capital investment needs that arise during the rate-setting plan that are incremental to an OEB prescribed materiality threshold. The requested amount for an ICM claim must be: incremental to a distributor's capital requirements within the context of its financial capacities underpinned by existing rates; and satisfy the eligibility criteria of materiality, need, and prudence. The OEB requires that a distributor requesting relief for incremental capital during the Price Cap IR plan term include comprehensive evidence to support the need. This includes the calculation of a rate rider to recover the incremental revenue from each applicable customer class. The incremental revenue is recognized in the year when the actual ICM related expenditures are expected to be in-service. This approach is consistent with the timing of the actual capital investment benefit to customers, which aligns with the expected timing of the OEB approval of ICM rate adjustments.

AUC is required to charge its customers for the following amounts (all of which, other than distribution rates, represent a pass-through of amounts payable to third parties):

- Commodity Charge - the commodity charge represents the market price of electricity consumed by customers and is passed through the IESO back to operators of generating stations. It includes the global adjustment, which primarily represents the difference between the market price of electricity and the rates paid to regulated and contracted generators;
- Retail Transmission Rate - the retail transmission rate represents the costs incurred in respect of the transmission of electricity from generating stations to local distribution networks. Retail transmission rates are passed through to operators of transmission facilities;
- Wholesale Market Service Charge ("WMS") - the WMS charge represents various wholesale market support costs, such as the cost of the IESO to administer the wholesale electricity system, operate the electricity market, and maintain reliable operation of the provincial grid. Wholesale charges are passed through to the IESO; and
- Distribution Rate - the distribution rate is designed to recover the costs incurred by AUC in delivering electricity to customers, including the OEB-allowed cost of capital. Distribution rates are regulated by the OEB and include fixed and variable (usage-based) components, based on a forecast of AUC's customers and electricity load.

Rate Applications

2019 Rates Application

On June 7, 2018, AUC filed an application for all four predecessor utilities (rate zones) for the approval of 2019 electricity distribution rates, effective January 1, 2019 to December 31, 2019. On December 20, 2018, the OEB issued its Partial Decision and Order on this application, approving distribution rates effective January 1, 2019, with an implementation date of February 1, 2019. On January 31, 2019, the OEB issued its Decision and Order on AUC's request for ICM funding. Both the effective and implementation date of the ICM rate riders was March 1, 2019.

On August 9, 2018, GHESI filed an application for the approval of 2019 electricity distribution rates, effective January 1, 2019 to December 31, 2019. On December 13, 2018, the OEB issued its Decision and Rate Order on this application, approving distribution rates effective January 1, 2019.

The following rate changes were effective as of the implementation dates:

- Horizon Rate Zone - Fourth annual update to the Custom Incentive rate plan. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kilowatt hours ("kWh") per month is an increase of approximately $0.28 or 1.03%;
- Brampton Hydro Rate Zone - Price Cap adjustment under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month is an increase of approximately $0.39 or 1.58%;
- PowerStream Rate Zone - Price Cap adjustment and ICM rate rider under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month is an increase of approximately $0.41 or 1.46%;

- Enersource Rate Zone - Price Cap adjustment and ICM rate rider under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month is an increase of approximately $0.15 or 0.58%; and
- Guelph Rate Zone – Price Cap adjustment under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month is a decrease of approximately $0.04 or 0.12%.

2020 Rates Application

On May 28, 2019, AUC filed an application for all five predecessor utility rate zones for the approval of 2020 electricity distribution rates, effective January 1, 2020 to December 31,2020. As part of the application, AUC filed its first five-year Distribution System Plan ("DSP") on an integrated basis for its entire service area. AUC requested approval for incremental capital funding based on a rate-adjustment mechanism that reconciles the capital needs set out in the DSP with the capital- related revenue in rates (the "M-factor"). On December 12, 2019, the OEB issued its Partial Decision and Interim Rate Order on the Price Cap IR elements of the application, approving distribution rates on an interim basis effective January 1, 2020. On January 30, 2020, the OEB issued its Partial Decision and Order on the M-factor. The OEB denied AUC's M-factor proposal but offered options for AUC to refile under its ICM rate setting mechanism on a single or multi-year basis, which AUC intends to pursue in 2020.

The following rate changes are effective as of the implementation dates:

- Horizon Rate Zone – Price Cap adjustment and incremental capital funding under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Horizon Rate Zone will be an increase of approximately $0.09 or 0.35%;
- Brampton Hydro Rate Zone – Price Cap adjustment and incremental capital funding under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month will be an increase of approximately $0.43 or 1.75%;
- PowerStream Rate Zone – Price Cap adjustment and incremental capital funding under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month will be an increase of approximately $0.35 or 1.21%;
- Enersource Rate Zone – Price Cap adjustment and incremental capital funding under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month will be an increase of approximately $0.46 or 1.80%; and
- Guelph Rate Zone – Price Cap adjustment and incremental capital funding under the OEB's Price Cap IR. The resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month will be an increase of approximately $0.20 or 0.68%.

Please refer to https://www.alectrautilities.com/about-alectra/regulatory/ for the status of the Corporation's rate applications.

Select Energy Policies and Regulations Affecting the Corporation in 2019

Amendments to the Ontario Rebate for Electricity Consumers Act, 2016 and associated Regulations

The Ministry of Energy, Northern Development, & Mines has amended portions of the Ontario Rebate for Electricity Consumers Act, 2016 ("OREC") and associated Regulations as part of its effort to improve the transparency of electricity costs for consumers. Beginning November 1, 2019, the following changes were mandated:

1. The subsidies from the Fair Hydro Plan are removed from the Regulated Price Plan;
2. The 8% OREC, otherwise known as the 'Provincial Rebate' line item was removed;
3. An additional line item entitled the Total Ontario Electricity Support, was added, comprising all other forms of support provided to customers, previously identified separately as each of the Ontario Electricity Support Program; Rural or Remote Rate Protection; Distribution Rate Protection; and First Nations Delivery Credit.

The impact of these changes resulted in a net discount on customer bills of 31.8% and is a single item on the bill, entitled Ontario Electricity Rebate. These changes are generally applicable to low volume customers. However, the amendments to the regulations also amend the eligibility criteria for customers. Certain groups of customers will now be excluded from the rebate altogether.

in millions of Canadian dollars

Customers in the General Service >50 kW category will need to provide their local distribution company with a self-declaration form in order to determine their eligibility. If no declaration is received by January 31, 2020, then customers would lose the discount beginning February 1, 2020, until the declaration is provided, assuming they qualify. If a customer was previously receiving the rebate and would now not be eligible under the new criteria, they can continue to receive the discount until October 31, 2020 provided a declaration is issued by February 1, 2020.

Customer Service Rules

On December 18, 2018, the OEB provided notice under sections 70.2 and 45 of the OEBA of proposed amendments to the Distribution System Code ("DSC"). The amendments were proposed as a result of the OEB's Phase 1 of its Review of Customer Service Rules. The Board issued the following amendments affecting service charges, as follows:

- Elimination of the collection of account charge;
- Elimination of the install/remove load control device charge; and
- Elimination of reconnection charge for eligible low-income customers.

On December 12, 2019, in its Partial Decision and Interim Rate Order on AUC's Rate Application, the OEB approved a variance account to recover the lost revenues associated with the removal of the collection of account charge. The OEB also included other amendments affecting Alectra Utilities' business, as follows:

- Security Deposits – Security deposit requirements should be waived for new residential customers enrolling in the utility's equal billing and/or pre-authorized payment plan;
- Minimum Payment Period – The OEB increased the minimum payment period from 16 calendar days to 20;
- Equal Billing Plans – Distributors should offer non-seasonal residential customers (except customers enrolled with retailers) an equal billing plan. Distributors should offer the equal billing plan to small business customers subject to certain exceptions;
- Allocation of Payment – Allow utilities (but not require them) to allocate payments in a manner that is different from the OEB-prescribed allocation method;
- Arrears Payment Agreements ("APA") – Distributors should not charge late payment charges on the amount that is covered by an OEB-prescribed APA; and
- Winter Disconnection period – The beginning of the disconnection ban period will change from November 15th to December 1st. Further, the OEB will allow for disconnection notices to be issued in April in order for disconnections to commence as of May 1st.

Amending Electricity Distributor Licenses to Remove the Conditions in Respect of CDM Targets

Since January 1, 2011, licensed electricity distributors have had conditions in their licenses related to the achievement of CDM targets. In March 2019, a directive was issued by the government to discontinue the Conservation First Framework and the conditions related to the achievement of CDM targets. In August 2019, the OEB amended the licenses of electricity distributors by removing conditions in respect of CDM targets.

Please refer to the Consolidated Financial Statements for a full description of energy policies affecting the Corporation.

Key Business Statistics

	2019	2018	2018 OEB Benchmark[1]
System average interruption duration index ("SAIDI")(2)	1.07	1.08	0.93
System average interruption frequency index ("SAIFI") (3)	1.26	1.37	1.25

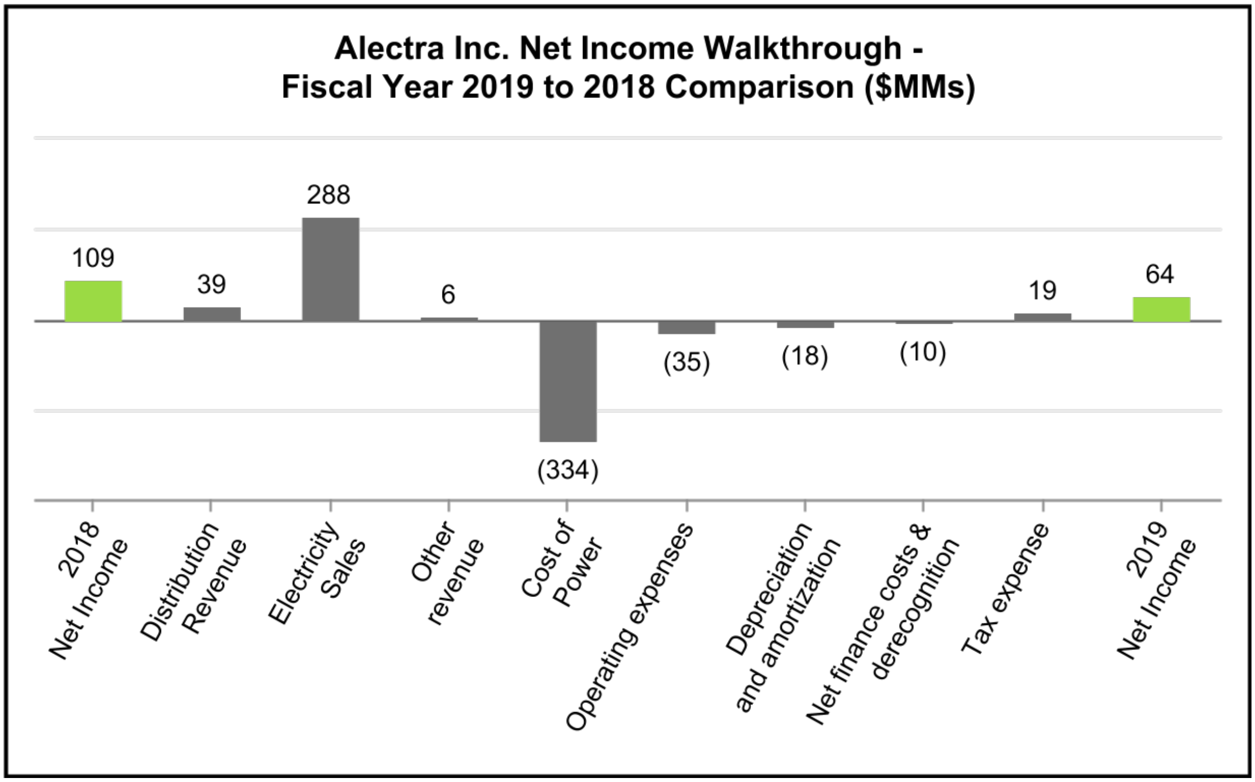
(1) The 2018 OEB benchmark is based on the average SAIDI and SAIFI index (excluding Hydro One Networks and rural distribution utilities) from the 2018 yearbook of Ontario electricity distributors.

[(2)] SAIDI equals the average duration of a sustained interruption per customer during a predefined period of time. A sustained interruption has a duration greater than or equal to one minute, adjusted for loss of supply and major events. The lower the SAIDI, the better the reliability. SAIDI figures presented in the table above are in hours.

[(3)] SAIFI equals the average number of times a customer experiences a sustained interruption over a predefined period of time. A sustained interruption has a duration greater than or equal to one minute, adjusted for loss of supply and major events. The lower the SAIFI, the better the reliability.

In 2019, AUC's SAIFI was 1.26, compared to 1.37 in 2018. This decrease is primarily attributed to lower underground cable failures and a lower number of adverse weather events in 2019.

RESULTS OF OPERATIONS



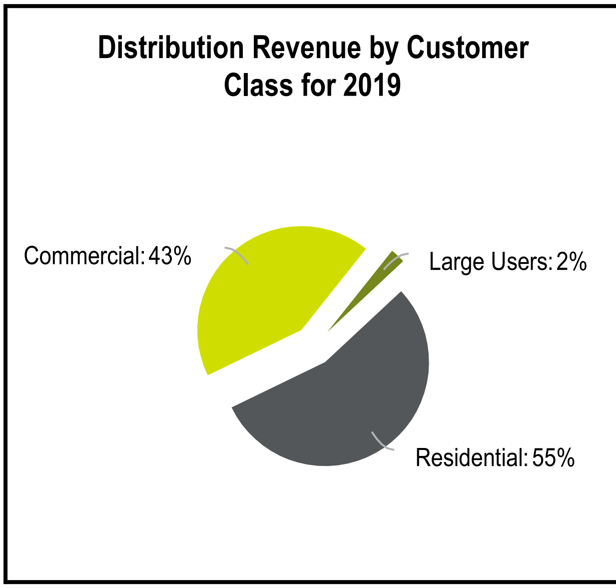
AUC amalgamated with GHESI on January 1, 2019. The former GHESI's 2018 financial results have not been included in the 2018 comparative figures.

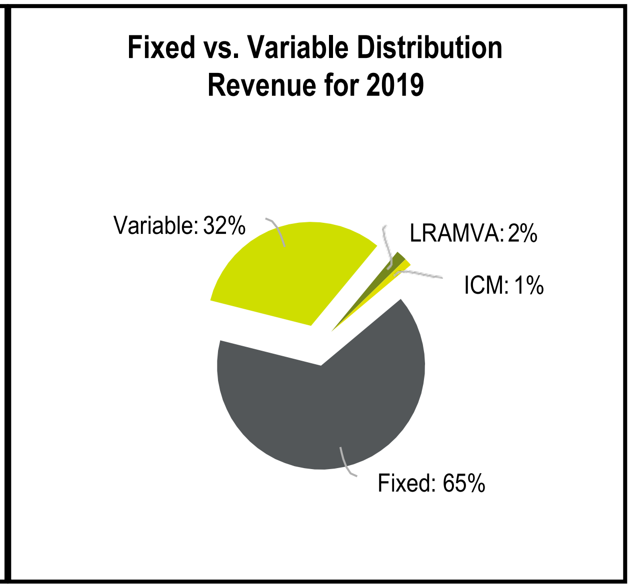
Net income for the year ended December 31, 2019 was $64 which is $45 lower than 2018 net income of $109. The decrease in net income is principally attributable to: (i) an increase in cost of power of $334 due to the inclusion of the former GHESI, which amalgamated with AUC on January 1, 2019 and was not included in the 2018 results ($237) and higher wholesale prices ($97); (ii) higher operating expenses ($35) mainly due to wage and benefit inflation and amalgamation with GHESI; (iii) higher depreciation and amortization costs ($18) due to new-in service asset additions in 2019; (iv) higher net finance costs ($10) due to interest on a new debenture issued in 2019; partially offset by (v) an increase in electricity sales driven by the inclusion of former GHESI electricity sales in the current year ($288); (vi) higher distribution revenue of ($39) due to the inclusion of GHESI which was not included in distribution revenue in 2018; (vii) lower income taxes ($19) due to lower net income in 2019; and (viii) higher other revenue ($6) due to higher consulting and billing services.

in millions of Canadian dollars

	2019	2018	Change
Distribution Revenue	544	505	39

Distribution revenue is recorded based on OEB-approved distribution rates to recover the costs incurred by AUC in delivering electricity to customers. The increase in distribution revenue mainly comprises: (i) higher distribution revenue from the former GHESI which was not included in distribution revenue in 2018 ($31); and (ii) higher distribution revenue as a result of higher distribution rates and a 1% increase in customer growth mainly driven from residential and small commercial classes ($8).





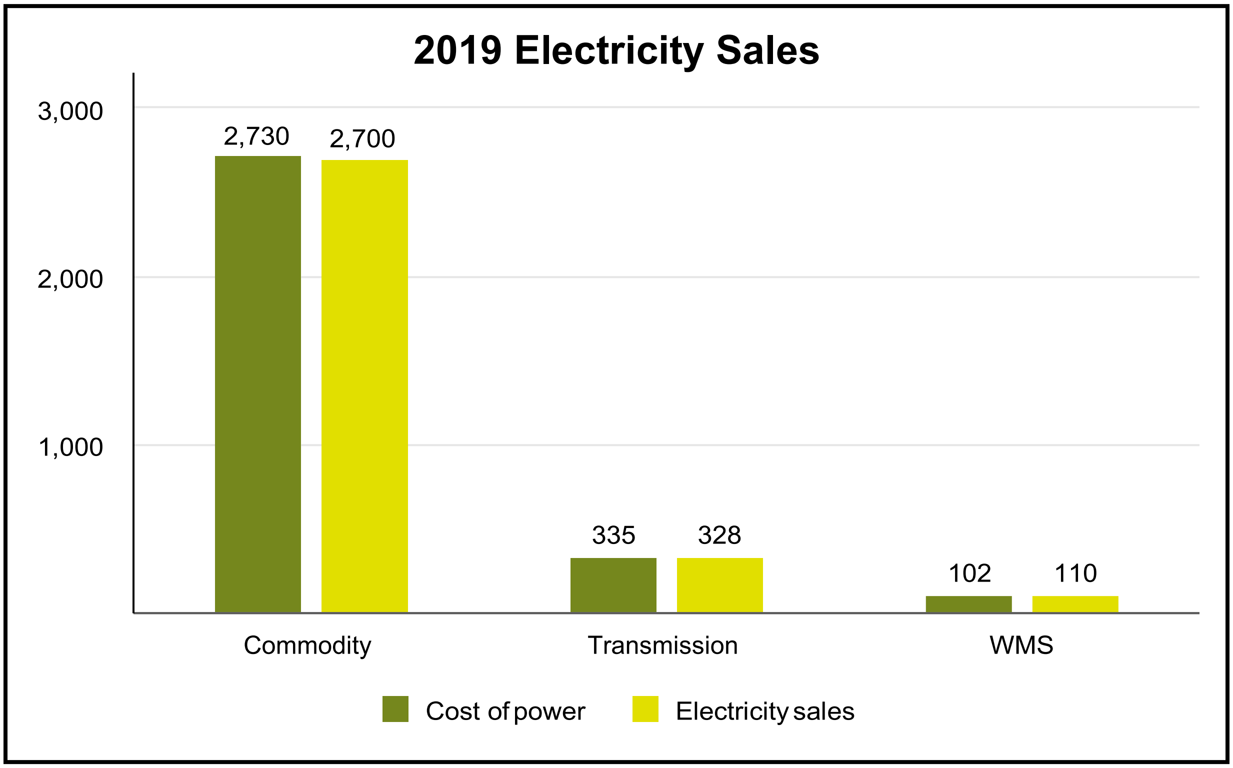
AUC's customer classes are as follows:

- Commercial - the commercial class typically includes small businesses and bulk-metered multi-unit residential establishments that is provided to customers with a monthly peak demand of less than 5,000 kW averaged over a twelve-month period;
- Residential - the residential class includes single family or individually metered multi-family units and seasonal occupancy;
- Large users - customers in the large users class have a monthly peak demand of 5,000 kW or greater averaged over a twelve-month period.

	2019	2018	Change
Electricity Sales	3,138	2,850	288

Electricity sales arise from the responsibility of the Corporation for billing customers for electricity generated by third parties and the related costs of providing electricity service, as shown in the chart below. The amounts that the Corporation is billed by such third parties often differ from the amount that the Corporation recovers from its customers. The difference between sales of energy and the corresponding cost of power is a timing difference ultimately recoverable from or repayable to ratepayers prospectively through annual applications to the OEB to adjust the rates of the Corporation to settle such timing differences. Such differences as at the end of the prior fiscal year are generally settled over a twelve month period as of the effective date of such annual applications; or more generally, the thirteenth to twenty-fourth month following the end of the prior fiscal year.

The increase in electricity sales ($288) is mainly driven by the inclusion of former GHESI electricity sales in the current year results.



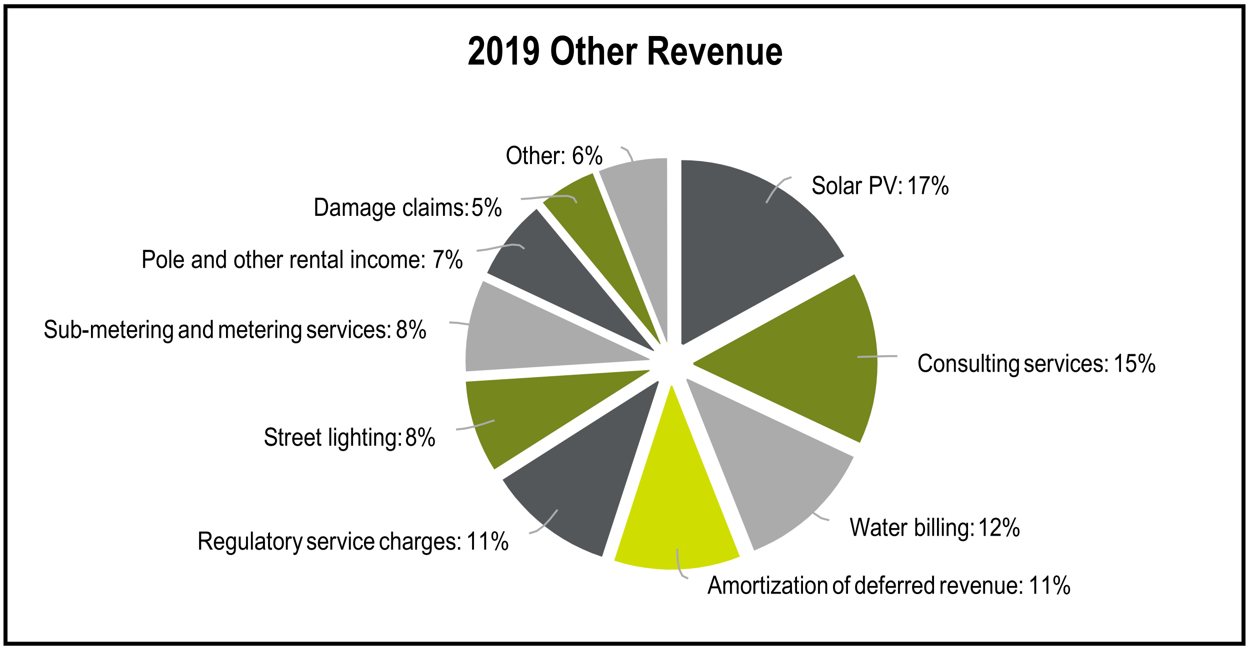
	2019	2018	Change
Other Revenue	97	91	6

Other revenue is earned from regulated electricity distribution activities as well as non-regulated activities. Other revenue from regulated activities includes:

- the amortization of deferred revenue related to capital contributions from developers;
- rates charged to customers for connections, reconnections, late payments, ancillary services, customer contributions;
- pole attachment charges to other utility service providers that attach equipment to poles owned by AUC; and
- CDM incentives and gains on sale of investments.

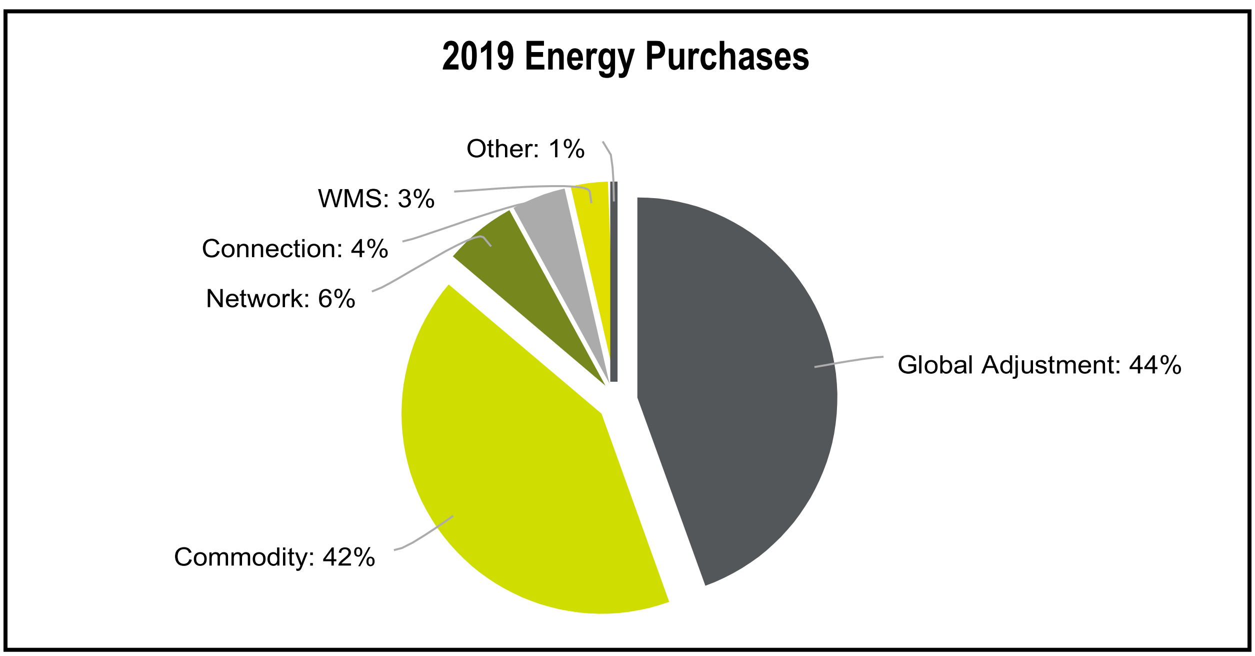
Non-regulated activities include: generation revenue from the Solar Photovoltaic projects; consulting services; water billing services; street lighting services; and sub-metering and metering services.

The increase in other revenue ($6) primarily relates to: (i) higher consulting and billing revenue from new contracts; (ii) higher regulatory service charges as a result of the merger with GHESI; (iii) higher sub-metering and metering services; partially offset by (iv) lower revenue on CDM programs resulting from the termination of the Conservation First Framework funding.



	2019	2018	Change
Cost of Power	3,167	2,833	(334)

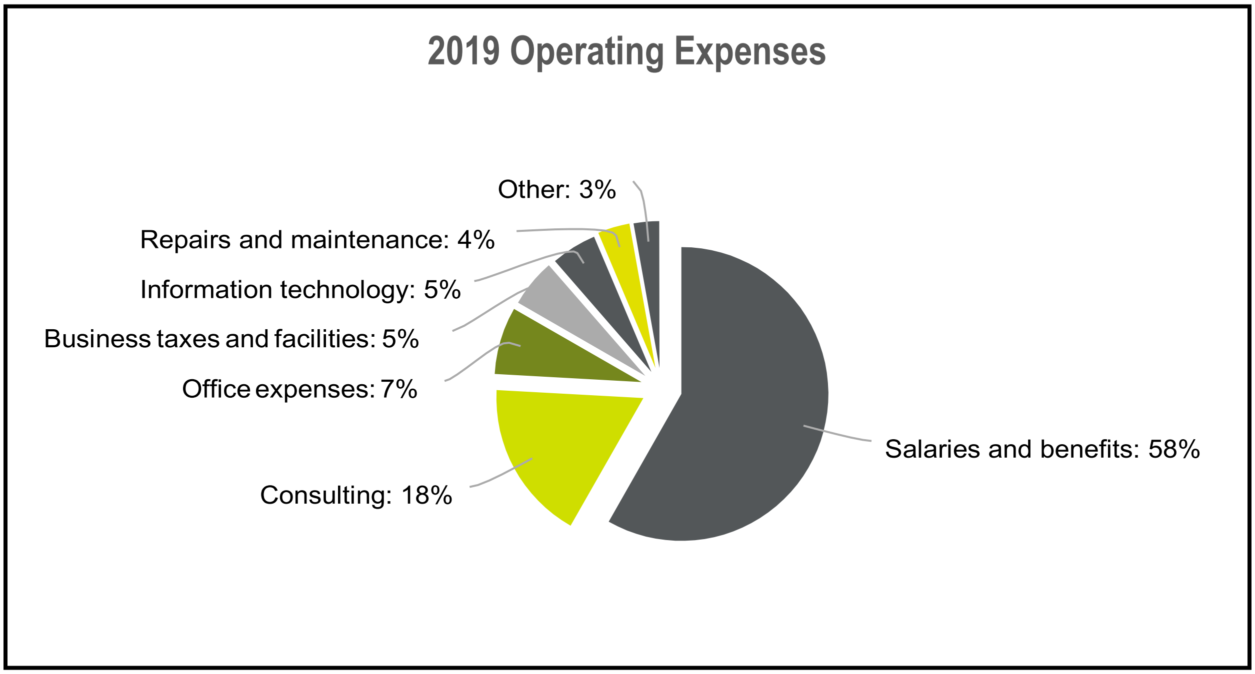
Cost of Power represents actual charges for electricity generated by third parties, which are delivered by AUC and passed through to customers in the form of energy sales. The increase in cost of power ($334) was primarily due to: (i) higher cost of power from the former GHESI not included in 2018 ($237); and (ii) higher cost of power as a result of higher wholesale electricity prices ($97).



in millions of Canadian dollars

	2019	2018	Change
Operating Expenses	296	261	(35)

Operating expenses primarily include salaries and benefits, materials and other third party service costs in support of the activities underlying the business of the Corporation including: (i) operation and maintenance of the distribution system; (ii) billing and collection; (iii) general administration costs; and (iv) costs in support of the non-regulated business activities. The increase in operating expense ($35) is principally due to: (i) higher direct labour costs ($23) corresponding to wage and benefit inflation ($12) and amalgamation with GHESI ($11); (ii) higher outside service provider expenditures ($10); (iii) higher expected credit losses related to uncollected balances ($4); partially offset by (iv) lower repairs and maintenance expenditures on vehicles and buildings ($3).



	2019	2018	Change
Depreciation and Amortization	158	140	(18)

The increase in depreciation and amortization expense ($18) is primarily due to new in-service asset additions in 2019, as well as the inclusion of depreciation from the amalgamation with GHESI in 2019.

	2019	2018	Change
Net finance costs and derecognition of property, plant and equipment	74	64	(10)

The increase in net finance costs and derecognition of property, plant and equipment ("PP&E") ($10) is primarily due to interest on a new debenture issued in 2019 and interest on debt acquired in the GHESI amalgamation.

in millions of Canadian dollars

	2019	2018	Change
Income Taxes	20	39	19

The Corporation and its subsidiaries, other than AESI and UA, are currently exempt from taxes under the *Income Tax Act (Canada)* and the *Ontario Corporations Tax Act* (collectively the "Tax Acts"). As a consequence of this exemption from income taxes under the Tax Acts, the Corporation is required to make payments in lieu of income taxes to the Ontario Electricity Finance Corporation ("OEFC"). These payments are calculated in accordance with the Tax Acts. These amounts are applied to reduce certain debt obligations of the former Ontario Hydro continuing in OEFC. AESI and UA are subject to the payment of tax under the Tax Acts.

The decrease in income taxes ($19) relates to lower net income before tax in 2019 relative to 2018.

FINANCIAL CONDITION

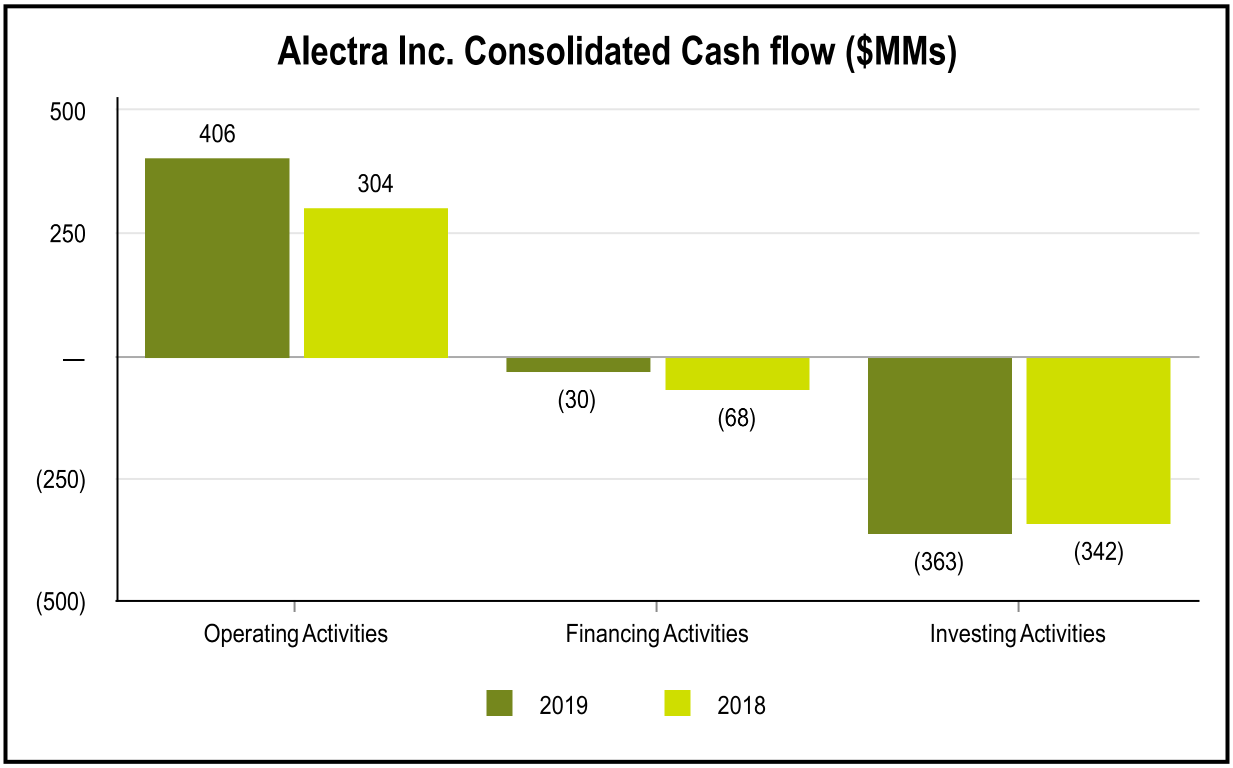
Significant changes in the Corporation's Financial Condition:

	2019	2018	$ Change	% Change	Explanation
ASSETS					
Accounts receivable and unbilled revenue	535	596	(61)	(10%)	The decrease in accounts receivable and unbilled revenue is primarily driven by lower energy consumption and an increase in the allowance for doubtful accounts.
Property, plant, and equipment	3,402	3,052	350	11%	The increase in PP&E is principally due to capital expenditures additions and the incorporation of PP&E balances from the former GHESI.
Goodwill and other intangible assets	998	936	62	7%	The increase in goodwill and intangible assets is due to an increase in goodwill associated with the amalgamation with GHESI and purchases of intangible assets.
LIABILITIES					
Short term debt	180	250	(70)	(28%)	The decrease in short term debt is principally due to refinancing from a new debt issuance completed in the year and changes in working capital balances.
Loans and borrowings	1,987	1,694	293	17%	The increase in loans and borrowings is primarily due to the issuance of a new debenture and the incorporation of debentures from the amalgamation with GHESI.
Deferred revenue	421	361	60	17%	The increase in deferred revenue relates to higher capital contributions to fund current capital access programs and the incorporation of the GHESI deferred revenue balance in 2019; partially offset by amortization in the year.

LIQUIDITY AND CAPITAL RESOURCES

Sources of Liquidity and Capital Resources

The principal sources of liquidity and capital resources comprise funds generated from operations and the financing and investing activities of the Corporation.



Operating Activities

The increase in net cash provided in operating activities was principally due to timing differences in relation to the settlement of receivable and payables (see note 26 in the Consolidated Financial Statements).

Financing Activities

The increase was primarily due to (i) the issuance of a new debenture in 2019; partially offset by (ii) the repayment of short term debt, and interest and dividend payments.

On April 11, 2019, the Corporation issued 3.458% senior unsecured debenture for $200 maturing in 2049.

In October 2018, the Corporation entered into a Commercial Paper ("CP") program. The program has a maximum authorized amount of $300 and is supported by the Corporation's $500 committed credit facility. The Corporation also has a $100 uncommitted credit facility. The Corporation may draw on the credit facilities for working capital and general corporate purposes. Interest on drawn amounts under the credit facilities would apply based on Canadian benchmark rates.

Short-term loans at December 31, 2019 and 2018 consist of CP issued under the Corporation's CP program. These short-term loans are denominated in Canadian dollars and are issued with varying maturities of no more than one year. CP issuances bear interest based on the prevailing market conditions at the time of issuance. CP issuance at December 31, 2019 was $180 (2018 - $250).

Long-term liquidity is available through the Corporation's ability to issue senior unsecured debentures under an established trust indenture. The rates of interest on such debentures comprise: government of Canada bond yields with terms of maturity corresponding to the terms of issued debentures; market-based credit spreads determined with reference to comparably rated entities; and costs of issuance. Details of the Corporation's long-term borrowings are provided in the Consolidated Financial Statements.

Dividends

During the year ended December 31, 2019, the Corporation declared and paid dividends as follows:

- Common share dividends aggregating $79 or $7.55 per share (2018 - $60 or $6.06 per share); and
- Class S share dividends aggregating $6 or $56.59 per share (2018 - $9 or $87.02 per share).

In addition, a return of capital of $4 (2018 - $5) was declared and paid by the Corporation on Class S shares during the year.

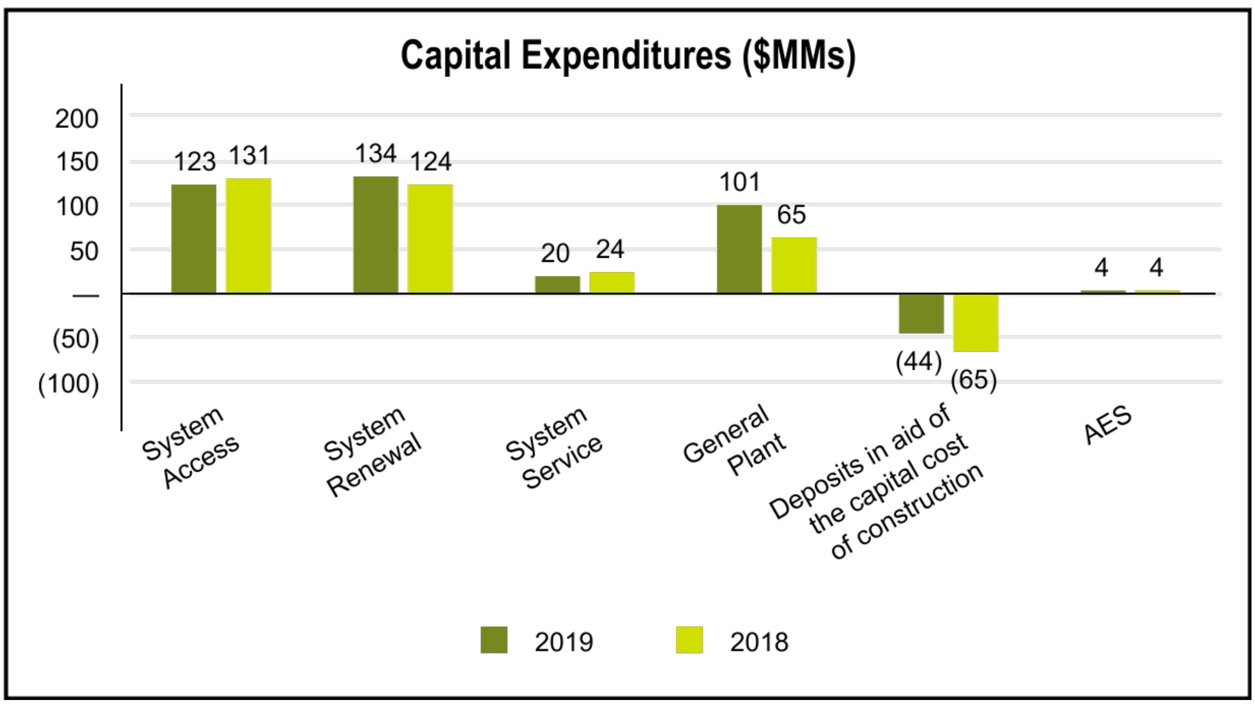
The Class S dividends, other than return on capital, are subject to Part VI.1 tax under the Income Tax Act (Canada) at a rate of 25% based on the amount of dividend paid. The Corporation is also eligible for a corresponding deduction equal to a specified multiple of the dividend. The deduction does not fully offset the Part VI.1 tax, resulting in a net effective tax rate of 1.8% on the Class S share dividends.

Investing Activities

Cash used in investing activities during the year increased by $21 primarily due to the purchase of property, plant and equipment and intangible assets in support of the expansion of the distribution system and to replace associated aging infrastructure.

Capital Expenditures

The Corporations gross capital investments are presented by activity in the table below:



System access expenditures relate to projects required to meet customer service obligations in accordance with the DSC of the OEB and corporate Conditions of Service. Projects in this category include: connecting new customers; building distribution infrastructure for new subdivisions; and relocating system plant for roadway reconstruction and major transit initiatives. Capital expenditures in this category have decreased by $8 relative to 2018, principally as a result of: (i) lower expenditures on transit projects ($31); partially offset by (ii) expanding the distribution system to connect new customers ($18) and (iii) the addition of former GHESI projects in 2019 ($5).

System renewal expenditures relate to long-term plans to replace assets that are at the end, or nearing the end, of their useful lives. Replacement strategies are prioritized based on both age and condition of assets, as well as the impact on system reliability. Capital expenditures in this category have increased by $10 relative to 2018, principally as a result of: (i) an increased number of renewal projects for assets that reached end of life ($15); (ii) inclusion of former GHESI projects in 2019 ($5); partially offset by (iii) a decrease in transformer renewal work ($5); and (iv) a decrease in substation renewal work ($5).

System service expenditures relate to projects required to support the expansion, operation and reliability of the distribution system. System service expenditures have decreased by $4 relative to 2018, principally explained by: (i) a decrease in transformer station expansion projects in 2019 ($10); partially offset by (ii) increased investment in system control, communications and automation as well as the inclusion of former GHESI projects in 2019 ($6).

General plant expenditures relate to information systems projects, facilities, and fleet. Capital expenditures have increased by $36 relative to 2018, principally due to: (i) the purchase of land for a new operations centre ($44); (ii) higher general expenditures for information technology, fleet, and facilities ($11); partially offset by (iii) a reduction in merger integration costs ($11); and (iv) reduced expenditures for connection and cost recovery agreement true-ups with Hydro One under the OEB Transmission System Code ($6).

Deposits in aid of the capital cost of construction are lower than the previous year ($21) primarily due to: (i) lower contributions consistent with the lower system access expenditures ($8); and (ii) changes in contributions relative to the prior year ($11).

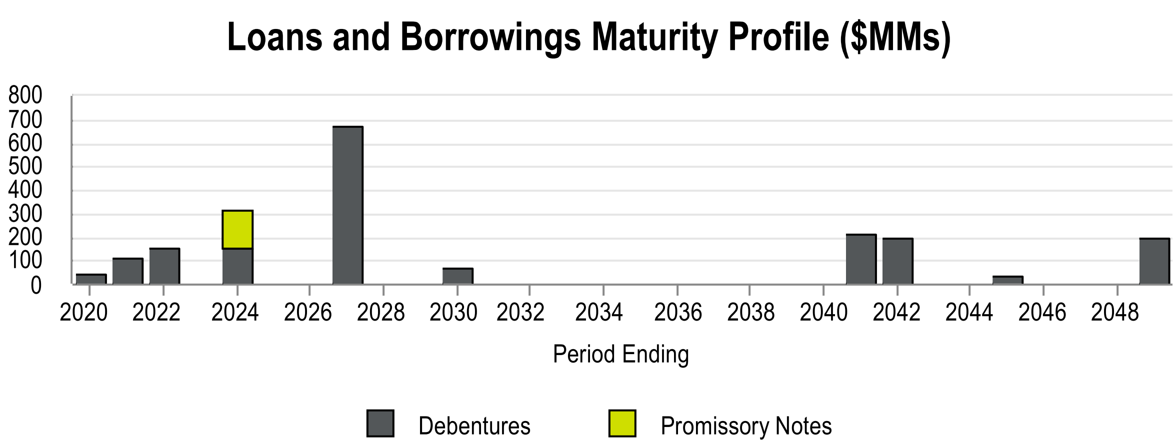
AES capital expenditures are principally attributable to the purchase of sub-metering assets.

Requirements for liquidity and capital resources

The Corporation has sufficient liquidity to meet the needs of its ongoing commitment to maintain, improve and expand its distribution system and competitive businesses, and invest in other infrastructure assets on a sustainable basis.

Summary of loans and borrowings

The following table presents a summary of the Corporation's loans and borrowings:



in millions of Canadian dollars

Summary of contractual obligations and other commitments

The following table presents a summary of the Corporation's debentures, major contractual obligations and other commitments:

	2020	2021	2022	2023	After 2024	Total
CP	180	—	—	—	—	180
Debentures - principal repayment	40	110	150	—	1,530	1,830
Debentures - interest payments	64	60	57	53	635	869
Promissory notes – principal repayment	—	—	—	—	166	166
Promissory notes – interest repayment	7	7	7	7	6	34
Leases	4	4	4	3	32	47
Total contractual obligations and other commitments	295	181	218	63	2,369	3,126

NON-IFRS FINANCIAL MEASURES

EBITDA

The Corporation uses earnings before interest, taxes, depreciation and amortization ("EBITDA"), comparable net earnings, and funds from operations ("FFO") as financial performance measures under Modified International Financial Reporting Standards ("MIFRS"). MIFRS adjusts IFRS results for the effect of rate regulation. 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 provided below. These non-IFRS measures are consistently applied in the previous period, except where otherwise noted.

	2019	2018
EBITDA (MIFRS)	356	356
Add adjustments to remove regulatory accounting:		
Revenue	(41)	(3)
Operating expenses	1	(1)
Loss on derecognition	—	(1)
EBITDA (IFRS)	316	351

Management believes that a measure of operating performance is more meaningful when including regulatory accounting in the results of operations as this better reflects the Corporation's normal operations.

in millions of Canadian dollars

AFFO

Adjusted funds from Operations ("AFFO") is used as an additional metric of cash flow without regard to changes in the Corporation's non-cash working capital and adjusted for contributions in aid of construction.

	2019	**2018**
IFRS Net income	64	109
Adjustment for regulatory activities	69	31
MIFRS Net income	133	140
Depreciation	158	131
Net loss on disposal	—	3
Amortization of deferred revenue	(11)	(9)
Net change in employee future benefits	11	5
Net change in non-cash operating working capital	(9)	(123)
Net change in deferred revenue	46	70
Net change in taxes	3	21
Total changes	198	98
AFFO	331	238

RISK MANAGEMENT AND RISK FACTORS

A proactive approach to risk management is vital to the long-term sustainability of the Corporation. This approach is documented within the Corporation's Enterprise Risk Management ("ERM") Framework.

An enterprise-wide review of risks and opportunities, as per the ERM Framework, was completed by the Corporation in 2019. This review included the assessment of risk, the identification of risk owners and documenting appropriate mitigation strategies. The details of the most significant risks identified are discussed below.

Culture & Organizational Change

The Corporation continues with its integration efforts with respect to the Merger Transaction creating the Corporation in 2017, including the establishment of a unified high-performing corporate culture. During this transition from legacy cultures, there is a potential risk associated with resistance to cultural change and conformance. The Corporation may experience some level of employee disengagement or loss of key employees. A failure to attract and retain qualified personnel could have a significant adverse effect on the Corporation. The Corporation has been working diligently through various means to establish a resilient culture including: the establishment of core values; employee engagement and communication initiative; and employee involvement in culture initiatives.

Regulatory/Political

The electricity distribution business in Ontario is highly regulated, which poses risks to the financial and operational aspects of the Corporation's rate regulated business. The Province and/or the OEB could implement a regulatory framework or issue directives or decisions that restrict the electricity distribution business from achieving an acceptable rate of return that permits the financial sustainability of its operations. All requests for changes in electricity distribution charges require the approval of the OEB.

The Corporation files applications to the OEB on an ongoing basis for rate adjustments in support of the sustainment and growth of its electricity distribution system. OEB decisions on current and future applications could have a significant impact on the distribution revenue of the Corporation in the future. The Corporation has an experienced management team dealing with these regulatory matters and continues to mitigate regulatory and political risk through participation in stakeholder groups, industry associations and other affiliations that are designed to inform the development of the legislative and regulatory environment.

Safety

The Corporation is engaged in the construction, operation and maintenance of high voltage electrical infrastructure throughout the communities it serves and, as such, is exposed to significant safety risks associated with this work. These risks include the potential for a major impact on the health and safety of the Corporation's staff or a member of the public. The failure to keep members of the public and employees safe could have a material adverse effect on the Corporation. The Corporation has recognized the high level of safety excellence achieved at the four legacy utilities and is building upon that foundation to implement an enterprise-wide safety management system. Safety is one of the Corporation's core values and, as such, the organization is focused on continual improvement of its safety performance.

Cyber Security

All businesses are at risk of cyber-attacks and are vulnerable to unauthorized access due to computer viruses, hacking, or other causes. A cyber-attack has the potential to cause service disruptions or system failure or could result in the disclosure of confidential customer or business information. Any such cyber-attack could have an adverse financial, operational and/or reputational impact on the Corporation. Due to the rapid change in technology and infrastructure security requirements of operating systems, the Corporation uses specialized internal resources and outside cybersecurity services to mitigate the potential for cyber security events. Policies, procedures and employee cyber security education programs are in place to reduce the risk of security breach. The Corporation is in the process of standardizing security tools across the enterprise as networks and systems from the legacy utilities are consolidated. These security enhancements include hardware, software as well as physical security at all facilities.

Although the Corporation has implemented security controls and other preventative measures to protect information and technology against cyber-attacks, there can be no assurance that such measures will be effective in protecting the Corporation's electricity distribution infrastructure or other assets from a cyber-attack or the effects thereof.

Credit risk

Credit risk is the risk that one party to a financial instrument will fail to discharge an obligation and cause the other party to incur a financial loss.

The principal source of credit risk for the Corporation corresponds to the realization of its customer receivables. The legislation governing the operation of Ontario's electricity industry exposes the Corporation, through its electricity distribution operations, to credit risk of several multiples of its means to generate revenue. Pursuant to Provincial regulation, electricity distribution companies in Ontario are required to act as the billing agent for all industry participants and must remit billed amounts accruing to these participants irrespective of whether such amounts are ultimately collected. Consequently, electricity distribution companies are exposed to losses for entire amounts billed to customers. Electricity distribution companies are not compensated for assuming this level of risk nor is there a clear and mechanistic regulatory means to recover losses for non-distribution charges.

Management has implemented credit and collection policies in compliance with OEB regulation to mitigate the exposure of the Corporation to credit risk, although such regulation is inadequate to effectively mitigate such risk. OEB regulation continues to impose certain restrictions on credit policy that exposes electricity distribution Corporations to unmitigated and uncompensated credit risk of several multiples of their means to generate revenue.

Management actively monitors and manages its exposure to credit risk, within regulatory constraints, and records credit losses in the period in which, in management's opinion, the collection of related receivables becomes doubtful.

As at year end, approximately $39 (2018 - $23) is considered over 60 days past due. Credit risk is managed, in part, through the collection of security deposits from regulated electricity distribution customers in accordance with regulations prescribed by the OEB.

Risk Associated with Debt Financing

The Corporation relies on debt financing or the availability of credit facilities to repay existing indebtedness and to finance its ongoing business operations including capital expenditures. The Corporation's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including financial market conditions, the regulatory environment in Ontario, the Corporation's results of operations and financial condition, the ratings assigned to the Corporation and its debt securities by credit rating agencies, the current timing of debt maturities, and general economic conditions.