Management's Discussion and Analysis
(In millions of Canadian dollars)

ALECTRA INC.

Eleven months ended December 31, 2017

INTRODUCTION

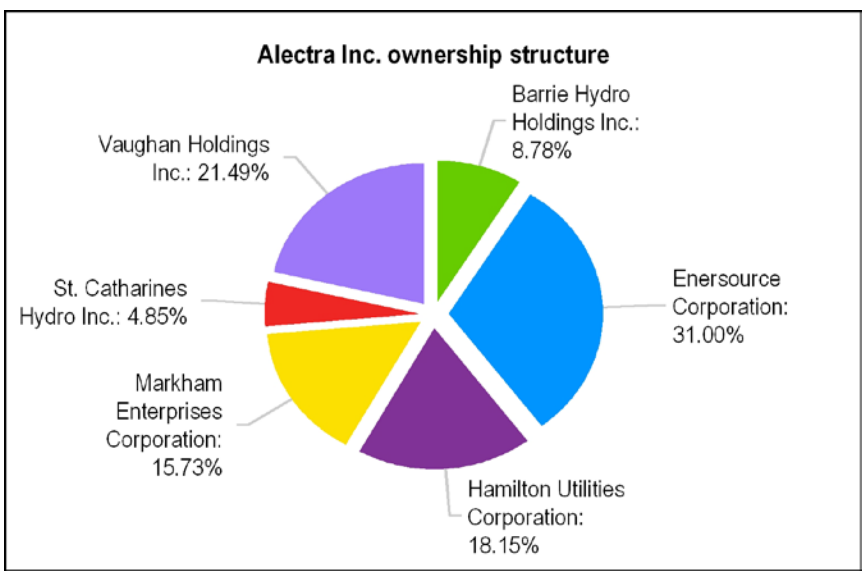
The following discussion and analysis of the consolidated financial condition and results of operations of Alectra Inc. (the “Corporation”) should be read together with its consolidated financial statements and accompanying notes for the 11 months ended December 31, 2017 (the “Consolidated Financial Statements”). As this is the first period of operation for the Corporation, no comparative period analysis has been provided.

The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”) and in effect at December 31, 2017. All dollar amounts in the tables are in millions of Canadian dollars, which are presented in whole numbers.

CORPORATE OVERVIEW

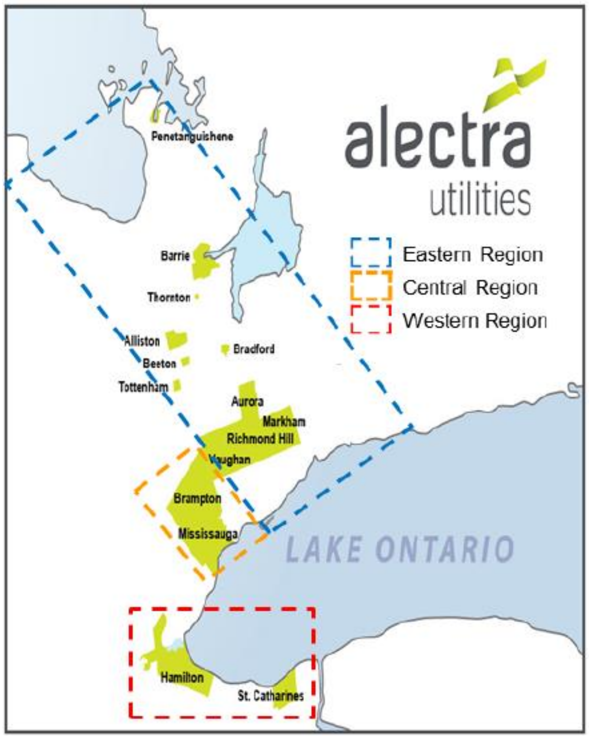
Alectra Inc. is an investment holding company that owns 100% of the common shares of each of: Alectra Utilities Corporation ("AUC"); Alectra Energy Solutions Inc. ("AES"); and Horizon Solar Corporation ("Horizon Solar"). The Corporation also indirectly wholly owns: Alectra Energy Services Inc. (“AESI”); Alectra Power Services Inc. (“APSI”); and Util-Assist (“UA”) which is wholly-owned by AESI. Alectra Inc. was created by (“Merger Transaction”): i) the amalgamation of the former entities (“Amalgamation Transaction”) PowerStream Holdings Inc. ("PowerStream Holdings"), Enersource Holdings Inc. ("Enersource Holdings"), and Horizon Holdings Inc. ("Horizon Holdings") (collectively, the “Amalgamating Entities”); and ii) the acquisition of Hydro One Brampton Networks Inc. ("Brampton Hydro") and its subsequent amalgamation with AUC.

Alectra Inc. is owned as follows:



Alectra Utilities Corporation

AUC was formed by the amalgamation of respective subsidiaries of the Amalgamating Entities as follows: PowerStream Inc. ("PowerStream"), Enersource Hydro Mississauga Inc. ("Enersource") and Horizon Utilities Corporation ("Horizon"). The principal business of AUC is the regulated distribution of electricity for residential and business customers within the municipalities of Barrie, Brampton, Markham, Richmond Hill, Vaughan, Aurora, Hamilton, St. Catharines, and Mississauga. The electricity distribution activities of AUC are regulated by the Ontario Energy Board ("OEB"), a Crown Corporation of the Province of Ontario. The OEB is the regulator of Ontario's natural gas and electricity industry. AUC provides electricity distribution to approximately one million customers is the second largest municipally-owned local distribution company (“LDC”) in North America by customers.



The Corporation earns revenue from this business by charging its customers for the use of the distribution system. Such electricity distribution service charges, or distribution charges, comprise a fixed periodic service charge combined with a volumetric charge based on electricity consumption. The distribution charges are approved by the OEB. AUC also provides Conservation Demand Management ("CDM") programs to its customers as a condition of its distribution license.

In addition to the electricity distribution business AUC also has a 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 Independent Electricity System Operator ("IESO") under the Feed-in -Tariff ("FIT") long term power purchase agreements ("FIT Agreements").

The Solar PV Business is delivered through: Ring Fenced Solar Portfolio ("RFSP"), a business unit within AUC; and Solar Sunbelt General Partnership (“Solar Sunbelt GP”) (99.99% ownership interest) of which AUC is the managing partner.

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.

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. AESI owns 100% of the shares of UA.

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

Horizon Solar Corporation

The sole business activity of Horizon Solar is its < 0.01% partnership interest in Solar Sunbelt GP.

CORPORATE STRATEGY

Vision

We will be Canada's leading electricity distribution and integrated energy solutions provider, creating a future whereby people, businesses and communities will benefit from energy's full potential.

Mission

We provide customers with smart and simple energy choices while creating sustainable value for our shareholders, customers, communities, and employees.

Values

Safety:	Promote the importance of health, safety, and wellness;
Respect:	Ensure a successful and rewarding work environment by valuing others and their contributions, while acting with integrity;
Customer Focus:	Become the customers' ally by creating an exceptional customer service experience;
Excellence:	Continuously pursue superior performance of our social, environmental, and financial commitments; and
Innovation:	Advance the business through the continuous improvement of people, processes, and technology.

Strategy Overview

THEMES (What we do)	**MANAGING THE TRANSITION**	**OPTIMIZING OPERATIONS AND ENHANCING CUSTOMER EXPERIENCE**	**GROWING THE BUSINESS**	**BUILDING CORPORATE RESILIENCE**
GOALS (What we want to achieve in the next 5 years)	Deliver the outcomes planned in the merger business case	Optimize the operation of assets and related processes and enhance customer experience	Grow the core business through mergers and acquisitions and regional and community planning initiatives Grow the non-regulated business	Invest in our people and processes to meet the needs of our customers and stakeholders
STRATEGIC OBJECTIVES (How we will achieve our goals)	• Achieve the post merger integration synergies and shareholder dividends outlined in the merger business case • Maintain or exceed existing customer service levels, reliability performance and employee engagement • Evolve the separate corporate cultures into a MergeCo culture • Continue to make process improvements for best-in-class status	• Optimize operations and asset lifecycle management and related processes regarding asset rehabilitation and renewal • Invest in and leverage emerging technologies to enable and enhance operations optimization • Enhance grid integration to enable continued conservation & demand management and distributed generation endeavors • Enhance reliability through smart grid initiatives • Advocate for more predictable and balanced rate regulation to protect existing revenue teams and to acquire new revenue streams • Enhance customer engagement and leverage through various channels/technologies including social media	**Core business:** • Service organic growth requirements by building integrated regional and community smart energy plans promoting sustainability, affordability and reliability • Continue to explore and pursue merger and acquisition opportunities that are value accretive with a preference to greater urban density and geographic contiguity and expand our service area to the full extent of our municipal boundaries **Non-regulated business:** • Build on existing non-regulated lines of business in multiple jurisdictions to enhance the integrated energy solutions model (i.e. solar renewables, high voltage electrical servicing, sub-metering, meter service provider services) • Explore and pursue emerging opportunities that have the appropriate risk profile and rate of return and are complimentary to the existing asset-based businesses. Explore the feasibility of future technologies and investments • Develop market segmentation studies, financing plans and value propositions for each of the emerging lines of business	• Strengthen the development and engagement of our employees. • Attract and retain the best talent. • Be a focused, sustainable and flexible organization positioned to succeed in the evolving market and energy industry

ELECTRICITY REGULATION

The Ontario Energy Board Act, 1998 (Ontario) 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 local distribution companies ("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.

Alectra Utilities 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 and, as a result, these regulatory assets and liabilities have not been recorded in the Consolidated Financial Statements.

Rate Setting

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

The rate-making policies of the OEB are designed 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. 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. The ICM is intended to address capital investment needs arising during an incentive rate term that are incremental to a prescribed materiality threshold. 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 riders.

Mergers, Applications, Amalgamations and Divestitures Application to create the Corporation

In April 2016, Enersource, Horizon and PowerStream filed a Mergers, Acquisitions, Amalgamations and Divestitures ("MAADs") application (the "MAADs Application") with the OEB pursuant to the Handbook to Electricity Distributor and Transmitter Consolidation (the "MAADs Handbook") seeking approval for the Amalgamation Transaction and for the Corporation to purchase and subsequently amalgamate AUC with Brampton Hydro. The MAADs Application included a request for the OEB to approve the continuation of regulated rates and charges of the predecessor LDC's of the Corporation.

On December 8, 2016, the OEB issued its Decision and Order in respect of the MAADs Application. The OEB granted the requested approvals and also approved a rebasing deferral period of 10 years, under which, the Corporation will operate individual "rate zones" (based on the continuing rates and underlying regulated cost structures of the predecessor LDCs). These rate zones ("RZ") correspond to the predecessor utilities and are respectively described as follows: "Brampton RZ"; "Enersource RZ"; "Horizon RZ"; and "PowerStream RZ".

During the re-basing deferral period, all costs and benefits associated with the Merger Transaction accrue to the shareholders of the Corporation, subject to an earnings sharing mechanism ("ESM") in years 6 through 10 in the event that the regulated earnings of AUC exceed 3.00% above the regulated MARE. Any ESM outcome is shared equally between the shareholders of the Corporation and the electricity distribution ratepayers of AUC.

As provided within the OEB Report of the Board, Rate-Making Associated with Distributor Consolidation, the rate zones of the Corporation will continue on current respective rate plan terms until such respective terms expire. Upon the expiry of such, all rate zones will migrate to the Price Cap IR method. At its option, AUC is permitted to apply for: (a) inflationary increases to rates, adjusted for an efficiency factor; and (b) ICM rate adjustments that provide financing and recovery of incremental discrete capital projects.

Recent Rate Applications to the OEB

Prior to the Merger Transaction, the predecessor utilities to AUC filed separate applications for the approval of 2017 electricity distribution rates as follows:

- Enersource filed an annual Price Cap IR Application with the OEB on August 15, 2016 for distribution rates effective January 1, 2017 to December 31, 2017. On December 8, 2016, the OEB issued its Decision and Order on this application, approving rates effective January 1, 2017. Based on the Decision and Order, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Enersource RZ will be approximately $0.82 or 3.39%;

- On August 11, 2016, Horizon filed its second annual filing with the OEB under its five years Custom IR Application for distribution rates effective January 1, 2017 to December 31, 2017. The OEB issued its Decision and Order on this application on January 12, 2017, approving rates effective January 1, 2017. The rate order was implemented February 1, 2017. Based on the Decision and Order, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Horizon Utilities RZ will be approximately ($0.46) or (1.60%);

- Brampton Hydro filed an annual Price Cap IR Application with the OEB on August 15, 2016 for distribution rates effective January 1, 2017 to December 31, 2017. On December 8, 2016, the OEB issued its Decision and Order on this application, approving rates effective January 1, 2017. Based on the Decision and Order, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Brampton RZ will be approximately $0.54 or 2.31%.

- PowerStream filed a Custom IR Application with the OEB on May 22, 2015 for distribution rates effective January 1, 2016 to December 31, 2020. On November 10, 2016, the OEB issued its Decision and Order on this application, approving a one year Cost of Service rebasing of rates effective January 1, 2017. Based on the Decision and Order, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the PowerStream RZ will be approximately $2.96 or 11.7%.

AUC filed applications for the approval of electricity distribution rates effective January 1, 2018, with decisions pending, as follows:

- Horizon RZ - third annual update to the Custom Incentive rate plan for the Horizon RZ. Based on the relief sought in the 2018 Electricity Distribution Rate ("EDR") application, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Horizon Utilities RZ will be approximately ($1.68) or (5.94%);

- Brampton RZ - Price Cap adjustment and ICM rider under the OEB's Price Cap IR. Based on the relief sought in the 2018 EDR application, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Brampton RZ will be approximately $0.23 or 0.98%;

- PowerStream RZ - Price Cap adjustment and ICM rider under the OEB's Price Cap IR. Based on the relief sought in the 2018 EDR application, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the PowerStream RZ will be approximately $0.54 or 1.92%;

- Enersource RZ - Price Cap adjustment and ICM rider under the OEB's Price Cap IR. Based on the relief sought in the 2018 EDR application, the resulting change to the distribution portion of the bill for a typical residential customer consuming 750 kWh per month in the Enersource RZ will be approximately $0.41 or 1.67%.

Select Energy Policies and Regulation Affecting the Corporation

Regulatory reform

On December 14, 2017, the Minister of Energy established an expert review panel, led by Richard Dicerni, to modernize the OEB and ensure that it, and the electricity sector, can adapt to innovative services and new technologies. The mandate of the panel includes reviewing how the OEB can continue to protect consumers amidst a rapidly changing sector, support innovation and new technologies, and how the OEB should be structured and resourced to deliver on its changing role. The panel will consult with relevant stakeholders such as LDCs, industry and economic regulators from other jurisdictions throughout 2018, and will prepare an action plan for regulatory modernization by the end of 2018.

alectra
Discover the possibilities

Ontario's Fair Hydro Plan ("OFHP")

The Ontario Fair Hydro Plan Act, 2017 came into effect on June 1, 2017. The OFHP established the framework for initiatives to reduce residential and some certain small business electricity bills in Ontario by an average of 25%, and limit future increases to the rate of inflation for four years. The planned rate reductions were comprised of two phases. The first phase implemented on May 1, 2017 represented a reduction in Regulated Price Plan ("RPP") rates and the removal of the Ontario Energy Support Payment ("OESP") charge of $0.0011/kWh. The second phase was implemented on July 1, 2017 representing a further reduction in RPP prices and a reduction of the Rural and Remote Rate Protection ("RRRP") charge from $0.0021/kWh to $0.0003/kWh. During the year, the OFHP reduces the total electricity bill for eligible customers and, accordingly, reduces current accounts receivable and unbilled revenue and accounts payable and accrued liabilities for LDC. No effect on distribution revenue or expense is recognized by LDC in respect of the OFHP.

The OFHP also included Global Adjustment ('GA") Modifier credit, effective July 1, 2017, that provided a reduction of GA charges for eligible RPP customers that have a contract with a retailer or have opted out of the RPP. The GA Modifier credit of $0.0329/kWh was designed to provide a benefit that was equivalent to the reduction in the RPP prices.

Monthly Billing Requirement for Electricity Distributors in Ontario

On April 15, 2015, the OEB announced that, by the end of 2016, all electricity distributors in Ontario would be required to bill their customers on a monthly basis. This policy change incorporates an expectation that distributors will issue bills based on actual meter reads rather than estimates at least 98% of the time. The amendments regarding estimated billing and billing accuracy came into force on April 15, 2015. The amendment regarding monthly billing came into force on December 31, 2016. The PowerStream, Horizon and Brampton rate zones have implemented monthly billing as of the date of these consolidated financial statements. As part of its decision on the MAADs Application, the OEB permitted a deferral of the implementation of monthly billing for the Enersource rate zone until December 31, 2018.

New 2015-2020 Conservation and Demand Management ("CDM") Framework

On March 26, 2014, the Minister of Energy issued a directive to the OEB to amend the licenses of electricity distributors with new requirements to deliver CDM programs available to customers that are designed to: achieve energy reductions; meet regulated CDM requirements through either Independent Electricity System Operator ("IESO") programs, LDC programs, or a combination of the two; and make the results of local programs available to other distributors on request. The coordination and integration of CDM and Demand Side Management ("DSM") activities is intended to achieve energy efficiencies and deliver convenient integrated programs for electricity and natural gas customers. The OEB issued the amendments to LDC licenses on December 18, 2014.

On March 31, 2014, the Minister of Energy issued a directive to the IESO through the Conservation First Framework ("CFF") to coordinate, support and finance the delivery of CDM programs through LDCs to achieve a total of 7 Terawatt Hours of province-wide reductions in electricity consumption between January 1, 2015 and December 31, 2020. There are two funding models available under the CFF: Full Cost Recovery Program ("FCR") and Pay for Performance Program ("P4P").

FCR

Each of the predecessor utilities entered into an Energy Conservation Agreement ("ECA") with the IESO to deliver energy savings based on their respective IESO-determined target. The ECA became binding upon approval of each respective predecessor utility's CDM Plan. On June 28, 2017, Alectra Utilities submitted a joint CDM plan to amalgamate the legacy LDC CDM plans together to the IESO with Collus PowerStream and Erie Thames Powerlines. The plan was approved on October 1, 2017 bringing the total joint allocated target to 1,649,040 MWh energy savings over the years 2015-2020. The Collus CDM will continue after the investment in Collus is sold. Prefunding amounts are received at the beginning of the CDM plan, this amount is included in accounts payable and is $15. Monthly settlements are made with the IESO for reimbursements of expenses incurred, these amounts are included as an offset to the prefunding amount in accounts payable and amount to $4.

P4P

As part of the joint CDM plan, Alectra Utilities will deliver a "Retrofit" program (a program that upgrades energy inefficient equipment in commercial businesses) via the P4P funding model. Under P4P, the IESO will pay Alectra Utilities a fixed rate per kWh of verified energy savings. Under the P4P, Alectra Utilities bears the risk of covering all of its costs and the eligible funding is capped at a negotiated Internal Rate of Return. Alectra Utilities recognizes an account receivable from the IESO for $15 which is equal to the revenue calculated per the internal rate of return model. There is an amount payable of $3 which represents the difference between the funds received from the IESO and account receivable in relation to the verified and paid savings determined.

Regulatory assets and liabilities

In its capacity to set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from IFRS. Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding AUC's regulated revenues and expenditures.

On January 30, 2014, the IASB issued interim standard IFRS 14, *Regulatory Deferral Accounts*. This standard allows first-time adopters of IFRS to apply previous Generally Accepted Accounting Principles to account for rate-regulated assets and liabilities. As PowerStream Inc., the deemed acquirer under the Amalgamation Transaction, adopted IFRS prior to the issuance of the interim standard, it does not apply regulatory accounting treatment to certain balances and transactions arising from rate-regulated activities.

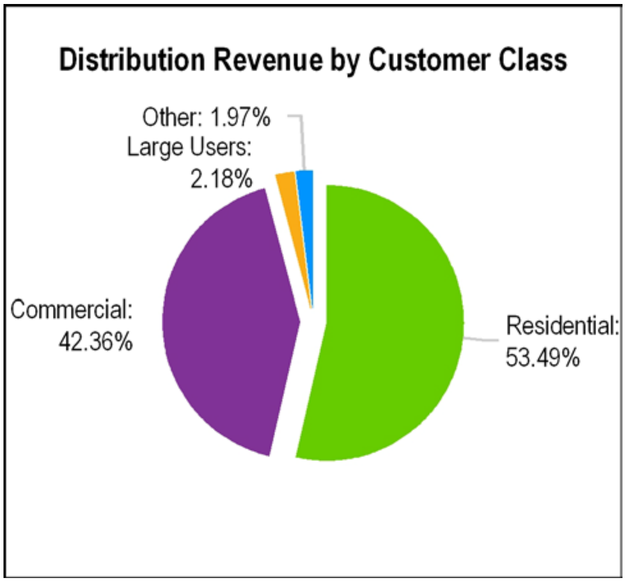
RESULTS OF OPERATIONS

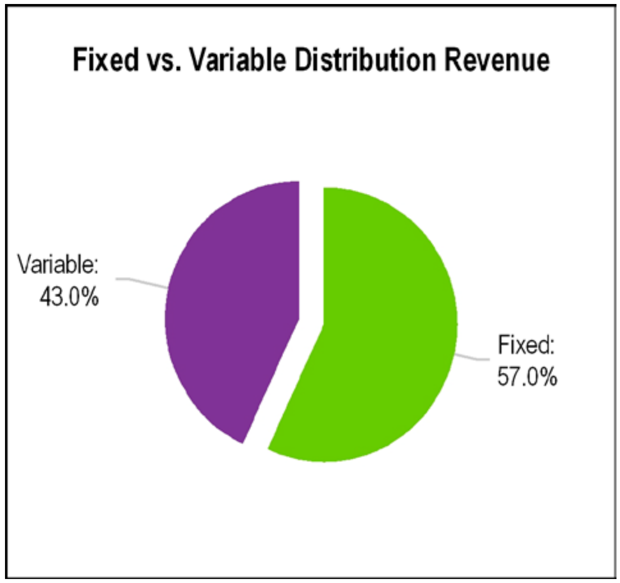
REVENUE

Distribution revenue	458

Distribution revenue of $458 is comprised of: (i) fixed distribution revenue ($258); (ii) variable distribution revenue ($204); (iii) ICM revenue ($3); and (iv) refund of past accumulated regulatory balances ($7).

Distribution revenue is recorded based on OEB-approved distribution rates, set at a level intended to recover the costs incurred by AUC in delivering electricity to customers, and includes revenue collected through OEB-approved rate riders.





Electricity sales	2,591

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, such as transmission services and other services provided by third parties. 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.

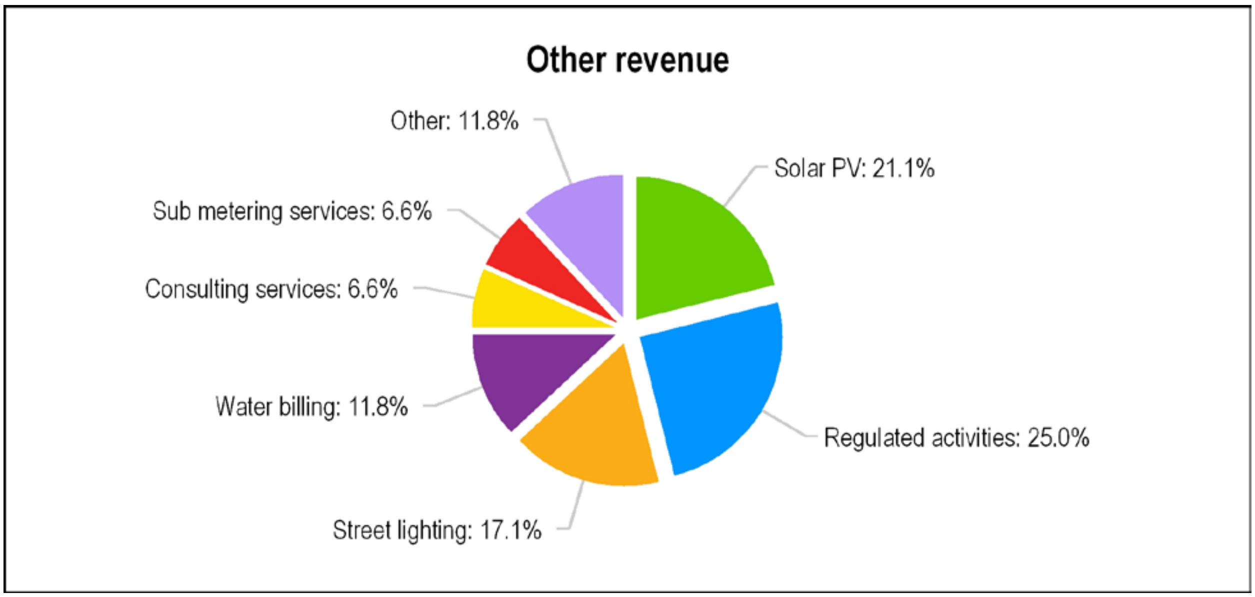
Other revenue	76

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;
- rates charged to customers for: connections, reconnections, late payments, ancillary services;
- customer contributions; and
- pole attachment charges to other utility service providers that attach equipment to poles owned by AUC.

Non-regulated activities include: sub-metering services; consulting services; street lighting services; and generation revenue from the Solar PV Business.

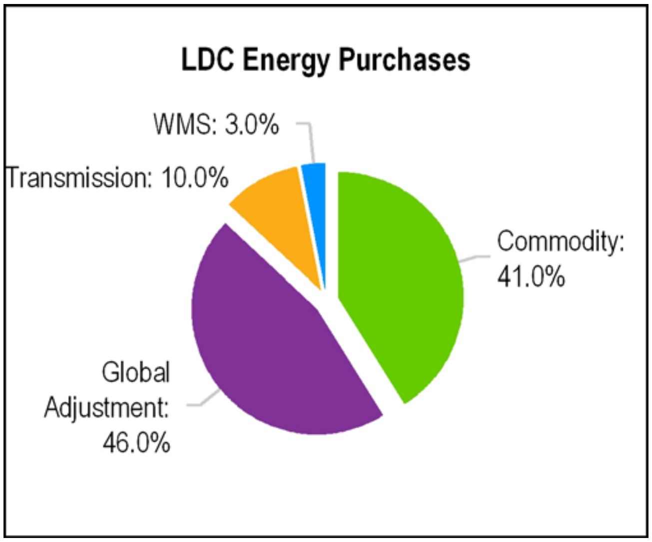
Other revenue is attributable to: (i) Solar PV Business ($16); (ii) regulated activities ($19); (iii) street lighting ($13); (iv) water billing ($9); (v) consulting services ($5); and (vi) sub-metering services ($5); other ($9).



EXPENSES

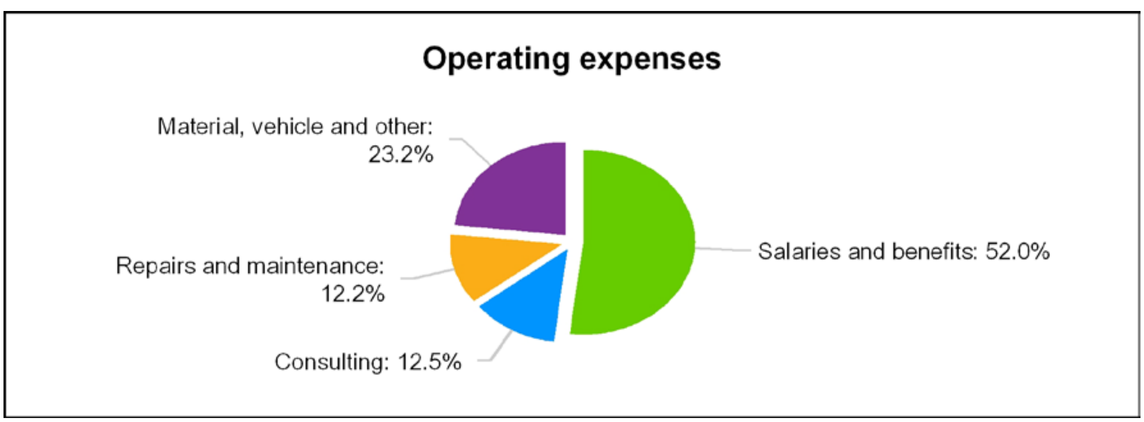
Cost of power	2,567

Cost of Power represents actual charges for electricity generated by third parties, which are passed through to customers over time in the form of energy sales. Please refer to the discussion under *Electricity Sales*.



Operating expenses	271

Operating expenses principally 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. Operating expenses are principally attributable to: (i) salaries and benefits ($141); (ii) consulting ($34); (iii) repairs and maintenance ($33); (iv) material, vehicle and other expenses ($63).



Loss on derecognition of property, plant and equipment	6

Loss on derecognition of property, plant and equipment represent the loss recognized when assets are replaced before the end of their useful life.

Depreciation and amortization	124

Depreciation and amortization expense comprises: depreciation on property, plant and equipment assets ($106) and amortization expense on intangible assets ($18).

Finance costs	
Finance income	(2)
Finance costs	55
Net finance costs	53

Finance income comprises of interest received on bank deposits.

Finance costs comprise interest expense on borrowings and are recognized as an expense in the statement of income and comprehensive income except for those amounts capitalized as part of the cost of qualifying property, plant and equipment.

Tax expenses	30

The Corporation and its subsidiaries, other than APSI, are currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act (collectively referred to as the “Tax Acts”).

Other than APSI, the Corporation is required to compute taxes under the Tax Acts and remit such amounts to Ontario Electricity Financial Corporation to be applied against certain stranded debt obligations of the former Ontario Hydro continuing in Ontario Electricity Financial Corporation.

APSI is subject to the payment of tax under the Tax Acts.

The statutory income tax rate for the current year comprises a 15% combined federal corporate tax rate and a 11.5% Ontario corporate tax rate. There was no change in the federal or provincial corporate tax rates in 2017.

A reconciliation of the statutory rate to the effective rate of tax expense is provided in the note disclosures to the Consolidated Financial Statements.

Subsequent event

Arbitration Judgment against the Corporation ("Arbitration Judgment")

The dispute in this arbitration arose from an agreement ("Project Agreement") between PowerStream Inc., continuing in Alectra Utilities, and another unrelated party ("Other Party") in connection with the development of renewable generation projects that would deliver electricity under the IESO FIT program. Based on the status of such projects and its interpretation of the Project Agreement, PowerStream Inc. delivered notice to terminate all projects under the Project Agreement in September of 2016. The principal issue in the arbitration is whether PowerStream Inc. was entitled under the Project Agreement to deliver such notice and, if not, the consequences that might ensue. The Other Party to the Project Agreement took the position that PowerStream did not have such entitlement.

The terms of the Project Agreement provided that such arbitration was binding without right of appeal.
On February 23, 2018, the arbitrator ruled against PowerStream Inc. and awarded the Other Party damages of $12,337,655 (not presented in millions) together with pre-judgment and post-judgment interest and costs of the arbitration. The ruling of the arbitrator further provided that such costs are to be paid by the Corporation to the Other Party.

Based on the award of damages and an estimate of pre-judgment and post-judgment interest and costs, the Corporation has recorded a liability of $13 with a corresponding charge to operating expenses. The claim may be subject to indemnification. The Corporation is presently investigating measures to mitigate this claim. Recoveries, if any, will be recorded in income on a prospective basis.

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 activities of the Corporation.

Cash, beginning of period	155
Net cash from operating activities	483
Net cash from financing activities	349
Net cash used in investing activities	(865)
Cash, end of period	122

Funds generated from operating activities

Cash from operating activities was $483 during the period. This amount is principally attributable to: (i) net income ($74); (ii) depreciation and amortization expense ($124); (iii) contributions received from customers ($62); and (iv) changes in non-cash operating working capital as a result of the timing differences in settlement of receivable and payables ($193).

Financing activities

Cash received from financing activities was $349. This amount is principally attributable to: (i) proceeds from issuance of loans and borrowings ($675); partially offset by (ii) repayment of loans and borrowings ($289); and (iii) dividends paid ($36).

Short-term liquidity is provided through funds from operations and revolving unsecured credit facilities aggregating $600MM comprising: i) $500MM committed facility with two Schedule A banks maturing January 31, 2019 ("Committed Facility"); and ii) $100MM uncommitted facility with a Schedule A bank which is callable by the bank. Under the terms of the Committed Facility, the Corporation can borrow, on a revolving basis, to finance general corporate requirements, capital investments, working capital requirements, and its prudential obligations to the IESO. Borrowings may be in the form of Bankers' Acceptances ("BAs"), prime rate loans and/or letters of credit. Interest rates payable on the credit facilities are based on a margin relative to the prime or BA rate, as the case may be, determined by reference to the Corporation's debt rating. As at December 31, 2017, in aggregate, $160 had been drawn under the credit facilities.

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.

Credit Ratings:

	DBRS		S&P Global	
	Credit rating	Trend	Credit rating	Outlook
Issuer rating	A	Stable	A	Stable
Senior unsecured debentures	A	Stable	A	Stable

On January 11, 2018, DBRS Limited ("DBRS") confirmed the credit rating on the Corporation as "A" with a stable trend.

On January 24, 2018, S&P Global confirmed the credit rating on the Corporation as "A" with a stable outlook.

The Corporation has sufficient available sources of liquidity and capital to satisfy working capital requirements for the next twelve months.

Investing activities

Cash used in investing activities was $865. This amount is principally attributable to: (i) The acquisition of Brampton Hydro ($615); and (ii) property, plant and equipment additions ($291); partially offset by (iii) contributions received from shareholders ($50).

Requirements for liquidity and capital resources

The Corporation's principal liquidity and capital resource requirements comprise its ongoing commitment to maintain, improve, and expand its distribution business and the Solar PV Business, and other infrastructure assets on a sustainable basis and in accordance with: governing statutes and regulations; working capital requirements; cost of power expense; the servicing and repayment of debt obligations; and the payment of dividends to its shareholders.

Summary of contractual obligations and other commercial commitments

The following table presents a summary of the Corporations debt and other major contractual commitments.

Contractual Obligations (due by year):	2018	2019	2020	2021	2022 and thereafter
Long Term debt-principal repayments	-	-	40	110	1,551
Long Term debt-interest repayments	59	59	59	55	514
Finance lease payments	1	1	1	1	12
Total contractual obligations	60	60	100	166	2,077
Other commercial commitments (by year of expiry):					
Bank line	-	500	-	-	100
Letters of Credit	40	-	-	-	-
Total other commitments	40	500	-	-	100

Capital Expenditures

The Corporations capital investments are split by company as noted in the table below:

AUC	
System Access	119
System Renewal	119
System Service	43
General Plant	15
Sub-total	296
Capital contributions	(62)
AUC total capital expenditures	234
AES	2
Total capital expenditures	236

System access expenditures relate to projects required to meet customer service obligations in accordance with the Distribution System Code ("DSC") of the OEB and corporate Conditions of Service. Projects in this category include: connecting new customers; building new subdivisions; and relocating system plant for roadway reconstruction work. In 2017 AUC invested $31.1 in capital for the York Region Transit project.

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.

System service expenditures relate to projects required to support the expansion, operation and reliability of the distribution system.

General plant expenditures includes modifications, replacements or additions to assets that are not part of the distribution system, including: land and buildings; tools and equipment; rolling stock; and electronics devices and software used to support day-to-day business and operations activities.

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

Dividend Requirements

During the period, the Corporation declared and paid dividends as follows:

- Common shares - $28, or $2.78 (dollars) per share;
- Class S shares - $8, or $81.00 (dollars) per share. These dividends are subject to Part VI.1 tax under the Income Tax Act (Canada) at a rate of 25% based on the amount of dividends 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 an effective tax rate of 1.8% on the Class S share dividends.

RELATED PARTIES

Related-party transactions are in the normal course of operations and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties and primarily consist of management, billing and administrative services, water and waste water billing and customer care services as well as amounts payable to/(receivable from) the City of Vaughan, the City of Markham, the City of Barrie, City of Mississauga, City of Hamilton, and City of St. Catharines. Details of these transactions are described more fully in the notes to the accompanying Consolidated Financial Statements.

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the amounts reported and disclosed in the consolidated financial statements.

Estimates and underlying assumptions are continually reviewed and are based on factors that are considered to be relevant such as historical experience and forecast trends. Actual results may differ from these estimates. Revisions of estimates are recognized prospectively.

Judgments are decisions made by management, based on analysis of relevant information available at the time the decision is made. Judgments relate to the application of accounting policies and decisions related to the measurement, recognition, and disclosure of financial amounts.

Accounting Estimates

The areas which require management to make significant estimates and assumptions in determining carrying values include, but are not limited to:

(i) *Unbilled revenue*

The measurement of unbilled revenue is based on an estimate of the amount of electricity delivered to customers between the date of the last bill and the end of the current period.

(ii) *Useful lives of depreciable assets*

Depreciation and amortization expense is based on estimates of the useful lives of property, plant and equipment, and intangible assets. The Corporation estimates the useful lives of its property, plant and equipment and intangible assets based on management's judgment.

(iii) *Valuation of financial instruments*

The measurement of financial assets and liabilities, which are not classified as loans and receivables, are based on an estimate of fair value based on discounted cash flow.

(iv) Employee future benefits

The cost of post-employment benefits is determined using actuarial valuations. The actuarial valuation incorporates estimates of discount rates, expected rates of return on assets, future salary increases, mortality rates, and future pension increases. Due to the long-term nature of these plans, such estimates are subject to significant uncertainty.

<u>Accounting Judgments</u>

(v) Cash Generating Units ("CGU")

Determining CGU's for impairment testing is based on management's judgment. This requires an estimation of the fair value less costs to sell or value in use. The value in use calculation requires an estimate of the future cash flows expected to arise from the CGU and a suitable discount rate in order to calculate a present value as a basis for determining impairment.

RISK MANAGEMENT AND RISK FACTORS

The ability to identify, manage and mitigate risk and uncertainty, maintain effective operations and respond appropriately to changes in the external and internal business environment is crucial to the continued success of the Corporation. The Corporation has established and implemented an Enterprise Risk Management ("ERM") System, as defined by the organizations ERM Framework, to provide a coordinated approach to assessing and responding to risks and opportunities that have an impact on the organization’s strategic objectives.

During 2017, the organization completed an enterprise-wide review of the risks with the potential to impact the organization. Risks were assessed based on their potential impact and their probability of occurring to determine the overall risk they pose to the organization. Internal risk owners were identified and strategies were developed to mitigate potential impacts. This process identified sixteen key risks; the highest rated risks are discussed in more detail below.

Culture

A significant risk associated with mergers and acquisitions is the integration of individual cultures and the potential for employee resistance to change. There is the potential for employee dissatisfaction if culture is not successfully defined and integrated, or loss of key knowledge should an employee choose to leave the organization without adequate knowledge transition. The failure to attract and retain qualified personnel could have a material adverse effect on the Corporation. With the merging of three standalone utilities and the acquisition of a fourth, the Corporation’s Senior Leadership Team ("SLT") has been working diligently to establish a resilient culture. The organization is defining and implementing a new corporate culture through employee engagement activities including clear and timely communications, development of change management tools and promotion of the Corporation’s Core Values which include Safety, Respect, Customer Focus, Excellence, and Innovation.

Safety

The Corporation is engaged in the construction, operation and maintenance of high voltage electrical infrastructure throughout the communities we serve and as such are 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 cyber security 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.

Collective Agreement

Unionized employees at the four legacy utilities were previously represented by different unions and, as a result, had separate collective agreements in place. In, 2017, unionized employees selected the Power Workers Union ("PWU") as their new collective bargaining agent. The Corporation is in the process of negotiating a unified collective agreement with the PWU for all represented employees. In the event of a labour dispute, the Corporation could face operational risks related to its ability to provide service to customers. The Corporation and PWU are working towards a mutually satisfactory collective agreement that will benefit represented employees and also create an environment in which the organization can achieve its strategic goals. It is anticipated that a new collective agreement will be in place in 2018. The Corporation is confronted by financial and operational risks related to its ability to negotiate a collective agreement.

Integration Projects

The Corporation is currently in the planning and/or implementation phase of several large operating/network system convergence projects. These projects include the Customer Information System ("CIS"), Enterprise Resource Planning System ("ERP"), and Graphical Information System/ Operations Management System ("GIS/OMS"). These large, complex projects pose risks related to cost overruns, scope changes and timeline delays that have the potential to impact the synergy savings identified within the Corporation's business plan for the Merger Transaction. Failure to successfully implement these projects could have an adverse financial, operational and/or reputational impact on the Corporation.

In order to mitigate these risks, dedicated teams of functional and technical experts have been, or are in the process of being, developed along with appropriate third party assistance from knowledgeable system integrators. These teams are supported by the Corporation's internal project management and change management expertise. These projects include the development of formal project charters and governance structures as well as regular review of project status, milestones, risks and issues to mitigate potential risks before or as they arise.

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.

Currently the Corporation has applications to the OEB for Price Cap IR and ICM rate adjustments. 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.

Other Risks

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. With the exception of the debt retirement charge, 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 accordance with the OEB regulation to mitigate the exposure of the Corporation to credit 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.

At December 31, 2017, approximately $20 is considered 60 days past due. Credit risk is managed through the collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2017, the Corporation holds security deposits from sub-metering customers in the amount of $2.

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 affecting its businesses, 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.

OUTLOOK

The principal focus of the Corporation is to provide customers with smart and simple energy choices while creating sustainable value for the shareholders, customers, communities, and employees.

The Corporation remains committed to meeting its strategic objectives, which include: managing the transition; optimizing operations and enhancing the customers experience; growing the business; and building corporate resilience. Business initiatives designed to meet these objectives include: maintaining or exceeding customer service levels, reliability, performance and employee engagement; enhance grid integration to enable continued CDM initiatives; continue to explore merger and acquisition opportunities; and strengthen the development and engagement of the Corporation's employees. Overall, management believes that the Corporation is well positioned to meets its strategic objectives while continuing to maintain a healthy financial condition.

On February 28, 2018, the Corporation entered into a *Merger Participation Agreement* ("MPA") with Guelph Municipal Holdings Inc. ("GMHI") and Guelph Hydro Electric Systems Inc. ("GHESI"). GMHI is the parent of GHESI. GHESI is principally an LDC regulated by the OEB.

The MPA provides terms and conditions under which the Corporation will amalgamate with GHESI. Subject to meeting certain conditions within the MPA, at the closing date, the Corporation will issue 485,000 Class G Common Shares to GMHI in consideration for all of the issued and outstanding shares of GHESI and, thereafter, AUC will amalgamate with GHESI. Such common share issuance by the Corporation would represent an effective 4.63% interest in its aggregate issued and outstanding classes of common shares. The effective interest conveyed was as negotiated between the parties based on the respective relative fair values of the Corporation and GHESI.

The merger is subject to the approval of the OEB based on a MAADs application expected to be issued thereto by the parties in early March. Subject to a satisfactory OEB decision approving the merger, the Corporation anticipates a closing date on or before January 1, 2018.

The Corporation expects that the merger contemplated under the MPA will result in more efficient and enhanced service delivery through lower operating costs while providing significant benefits for communities and shareholders.

FORWARD LOOKING STATEMENTS AND INFORMATION

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 about the credit facility;
- 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 and 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 disclaim 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;
- Favourable 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 unfavourable 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.

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 Management and Risk Factors” in this Management’s Discussion and Analysis. Readers should review this section in detail. In addition, the Corporation cautions the reader that information provided in this Management’s Discussion and Analysis 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.