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Alectra Financial Plan

2019 - 2023

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GLOSSARY of ACRONYMS and ABBREVIATIONS

The following acronyms and abbreviations are used in this document.

AESI	Alectra Energy Services
AFFO	Adjusted Funds From Operations
AMI	Advanced Metering Infrastructure
AR	Accounts Receivable
ATI	Achieving Target Incentive
BA	Banker's Acceptance
BPS	Basis points
CC&B	Oracle Customer Care and Billing System
CCAA	Companies' Creditors Arrangement Act
CCP	Community Conservation Program
CDM	Conservation and Demand Management
CIR	Custom Incentive Regulation
CFF	Conservation First Framework
CIS	Customer Information System
CP	Commercial Paper
CPI	Consumer Price Index
CPP	Canada Pension Plan
CX	Customer experience
DSC	Distribution System Code
DSCR	Debt service coverage test
EDR	Electricity Distribution Rate
EHT	Employer Health Tax
EI	Employment Insurance
EPC	Engineering, Procurement and Construction
ERP	Enterprise Resource Planning
ESB	Enterprise Services Business
ESM	Earnings Sharing Mechanism
FCR	Full Cost Recovery
FIT	Feed In Tariff
GA	Global Adjustment
GDP	Gross Domestic Product
GHESI	Guelph Hydro Electric Systems Inc
GIS	Geographic Information System
GoC	Government of Canada
GP	General Plant
GRE&T	Green Energy and Technology
GTAA	Greater Toronto Airports Authority
GWh	Gigawatt-hours
HaLRT	Hamilton Light Rail Transit
HONI	Hydro One Networks Inc.
HuLRT	Hurontario Light Rail Transit
ICM	Incremental Capital Module
IESO	Independent Electricity System Operator
IFRS	International Financial Reporting Standards
IoT	Internet of Things
IPI	Implicit Pricing Index
IR	Incentive Rate-Setting
IRR	Internal Rate of Return
ISO	International Organization for Standardization
IT	Information Technology
JDE	JD Edwards
kW	Kilo Watt
kWh	Kilo Watt Hour
LDC	Local Distribution Company
LED	Light-Emitting Diode
LRT	Light Rail Transit
LRAMVA	Lost Revenue Adjustment Mechanism Variance Account
MAADs	Mergers, Acquisitions, Amalgamations, Divestitures
MIFRS	Modified International Financial Reporting Standards
MDM	Meter Data Management
MOE	Ministry of Energy
MP	Wholesale Meter Point
MPA	Merger Participation Agreement
MSO	Meter Sealing Organization
MSP	Meter Service Provider
MTI	Mid-term Target Incentive
MTO	Ministry of Transportation
MWAC	Mega Watt AC Output Capacity
MWh	Mega Watt Hours
NTM	Next twelve months
O&A	Operations and Maintenance
OEB	Ontario Energy Board
OFHP	Ontario Fair Hydro Plan
OM&A	Operating, Maintenance, and Administration
OMERS	Ontario Municipal Employees Retirement System
OMS	Outage Management System
OPG	Ontario Power Generation
P4P	Pay for Performance
PACE	PowerAssist Call Engine
PP&E	Property, plant and equipment
Price Cap IR	Price Cap Incentive Regulation
PV	Photovoltaics
PWU	Power Workers Union
RALs	Regulatory Assets and Liabilities
RER	Regional Express Rail Project
RFSP	Ring-Fenced Solar Portfolio
ROE	Return on Equity
RPP	Regulated Price Plan
RZ	Rate zone
SA	System Access
SI	System Integrator
SLA	Service Level Agreement
SPN	Solar Power Network
SR	System Renewal
SS	System Service
SSIA	Solar Services Indemnity Agreement
TS	Transformer Station
TTM	Trailing twelve months
WSIB	Workplace Safety and Insurance Board

1.0 Introduction and Summary

The following report provides the 2019-2023 Consolidated Financial Plan ("2019 Plan") for Alectra Inc. ("Alectra"). Alectra has three distinct business segments: i) Local Distribution Company ("LDC"), which distributes electricity to approximately 1,000,000 customers and is the largest municipally-owned electricity distribution company in Ontario; ii) Solar Partnership; and iii) Energy Solutions. The 2019 Plan provides a 2019 Budget with a forward looking forecast for 2020 to 2023.

The narrative and analysis within the 2019 Plan primarily focuses on results for the LDC, Energy Solutions and Solar Partnership, which are shared among the Voting Common shareholders of Alectra Inc. Such results will be referred to as the "Consolidated Shared" position throughout the document.

[redacted]

Alectra's goal is to be Canada's leading electricity distribution and integrated energy solutions provider, creating a future where people, businesses and communities will benefit from the full potential of energy. The Alectra five year strategy was designed to address four strategic themes of:

- managing the transition;
- optimizing operations and enhancing customer experience;
- growing the business; and
- building corporate resilience.

The strategy provides a roadmap for Alectra's activities over the next five years. The strategy will help set the priorities for the organization and is at the core of the 2019 Plan. Recognizing the business is operating in a changing environment, Alectra will conduct an annual review of the strategy and the sector overall and seek stakeholder input in order to update the plan as needed.

[redacted]

On October 19, 2018, the OEB approved the MAADs application to amalgamate Alectra Utilities and Guelph Hydro into a combined LDC that will continue as Alectra Utilities. The 2019 Plan has been updated to include the net income and dividend impact of the Guelph Hydro merger in Table 1 based on figures from the Guelph merger business case. The 2019 Plan does not incorporate any of the underlying drivers of the merger with Guelph Hydro with the exception of Section 2.3, Table 16 which provides an impact analysis on net income and dividends for the existing shareholders. There are insufficient details from the GHESI merger business case to update all the relevant tables in this document.

The 2019 Plan incorporates revisions to capital and operating synergies and transition costs that have been identified subsequent to the completion of the 2018 Plan. It is anticipated that Alectra will deliver approximately $260.8MM in net capital and operating synergies over the six years following the merger, which compares unfavourably to the 2018 Plan by $33.3MM, and unfavourably by $35.1MM to the merger Business Plan. The 2019 Plan incorporates a reduction in synergies of $1.1MM and additional transition costs of $32.2MM relative to the 2018 Plan. A summary of all the underlying drivers are described in Section 2.4.

Alectra has developed a supporting financing plan that was previously approved in the 2018 Plan. The focus of the financing plan is to address cost effective liquidity to support sustainable business investment and growth objectives.

The dividend policy of the Corporation provides that shareholders of Voting Common shares are eligible to receive a non-cumulative dividend with a target of 60% of Alectra's Consolidated Shared MIFRS net income.

The following table provides a summary comparison between the 2019 Plan and 2018 Plan for the Consolidated Shared entity. The underlying drivers to the differences are analyzed in Section 4.0.

Table 1: Shared consolidated entity comparison between 2019 Plan and 2018 Plan by Year ($MMs)

		2018	2019	2020	2021	2022	Total	2023
[redacted]								
Operating Costs (LDC)	2019 Plan	243.4	247.8	224.4	228.3	232.0	1,175.9	238.7
	2018 Plan	255.8	230.3	226.4	229.0	232.8	1,174.3	NA
	Variance	**12.4**	**(17.5)**	**2.0**	**0.7**	**0.8**	**(1.6)**	**NA**
Net Capital Expenditures (LDC)	2019 Plan	284.8	271.9	254.6	251.3	252.8	1,315.4	257.0
	2018 Plan	307.8	272.9	270.6	269.9	272.9	1,394.1	NA
	Variance	**23.0**	**1.0**	**16.0**	**18.6**	**20.1**	**78.7**	**NA**
[redacted]								

*4.63% of earnings and dividends post-2018 accrue to the City of Guelph

The 2018 Plan identified challenges with respect to structural cost changes relative to the 2017 Plan. These challenges were addressed by Management with the result that the adverse impact of such were fully mitigated. The 2019 Plan demonstrates that Operating expenditures are, in fact, favourable to the 2018 Plan, principally as a result of measures introduced by Management.

This notwithstanding, the 2019 Plan results are significantly below the 2018 Plan results for the following reasons:

- Unexpected adverse Ontario Energy Board decision on Alectra Utilities 2018 ICM/ IR rate application that has implication to outcomes for similar future rate applications. The result is a significant overall decline in forecast distribution revenue relative to the 2018 Plan;
- Changes to customer service rules that have adverse implication to previous service charge revenue forecasts;
- [redacted]
- Higher depreciation costs resulting from: i) a shift in the capital plan towards faster amortizing Information Technology assets; and ii) changes in annual depreciation from in-service assets as a result of refinements to depreciation calculations in the course of harmonizing process.

The result is a decline in net income relative to the 2018 Plan as indicated in Table 1. The unfavourable 2019 Consolidated Shared net income variance is principally explained by severance deferral from 2018.

A reconciliation of MIFRS net income between the 2018-2022 Financial Plan ("2018 Plan") and the 2019 Plan has been provided in Section 4.0, Table 33 of this report.

The revenue challenges in the LDC signal increasing political and regulatory risks regarding customer rates and real return expectations for regulated distribution companies in Ontario. In the view of Alectra management, the 2018 Alectra rate application decision of the OEB was inconsistent with its decision on the Alectra merger application and associated OEB policies and principles regarding distributor consolidation. This notwithstanding, the OEB is not bound by its own policies or precedent decisions, which creates obvious risk for LDCs and their ability to deliver sustainable service to customers balanced with fair returns to shareholders.

The 2019 Plan assumes that Alectra will be able to successfully negotiate a collective agreement with the PWU and achieve outcomes in line with the merger business case. Achievement of planned synergies and financial results will be at risk if Alectra cannot negotiate a collective agreement that allows for staff relocation, operational changes and wage increases that are consistent with the assumptions underlying the 2019 Plan.

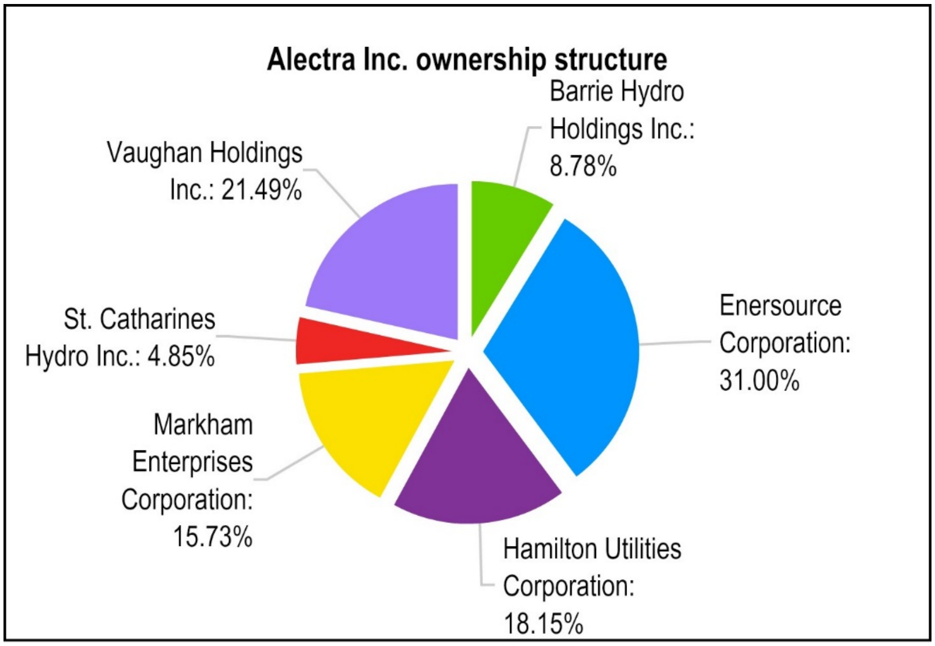
The challenges inherent in the 2019 Plan are described in more detail in Sections 4.0 and 6.0.

2.0 Introduction

2.1 Organizational Structure

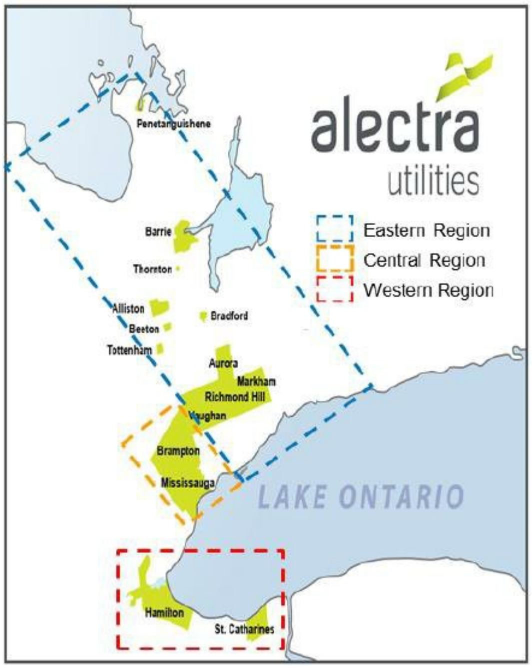
Alectra Inc. is an investment holding company that owns 100% of the common shares of each of: Alectra Utilities Corporation ("AUC"); Alectra Energy Solutions Inc. ("AES"); and Horizon Solar Corporation ("Horizon Solar"). The Corporation also indirectly wholly owns: Alectra Energy Services Inc. (“AESI”); Alectra Power Services Inc. (“APSI”); and Util-Assist (“UA”) which is wholly-owned by AESI.

Alectra Inc. is owned as follows:



Alectra Utilities Corporation

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.



AUC 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.

[redacted]

[redacted]

2.2 Basis of Presentation

Alectra prepares its consolidated financial statements in accordance with Modified International Financial Reporting Standard ("MIFRS") for internal management reporting, regulatory reporting, financial planning, and forecasting purposes. Alectra will also prepare consolidated financial statements in accordance with International Financial Reporting Standards ("IFRS") for statutory and other compliance purposes, such as with respect to lending arrangements. Such IFRS financial statements are not analyzed further in this 2019 Plan. In 2018, IFRS 15 *Revenue from Contracts with Customers* and IFRS 9 *Financial Instruments* standards were required to be implemented, with no impacts to the financial plan expected as a result of these new standards. On January 1, 2019, the new IFRS 16 standard on Leases becomes effective. The impact of this new standard is discussed in Section 2.3 of this plan.

MIFRS, as principally prescribed by the OEB, was determined as the basis for presenting internal management statements and forecasts, as it aligns the basis of reporting earnings and cash flow with the rate-regulated basis, which accrue to distribution utility shareholders.

2.3 Key Financial Plan Assumptions

The 2019 Plan is based on certain material assumptions of Management deemed reasonable in the circumstances.

2.3.1 REGULATED LDC

The success of the LDC is dependent on high operational performance of its assets and related processes while delivering reliable and responsive service to its customers. The principal objectives focus on improving asset utilization and process optimization while managing costs and enhancing customer engagement. In support of these objectives, the LDC will leverage new technologies and leading tools and work methods. The financial objectives will be focused on cost efficiency initiatives that improve earnings and/ or reduce customer costs.

The 2019 Plan provides for managed growth of expenditures, with due regard for expectations set by the OEB regarding: (i) the nature and magnitude of expenditures; (ii) prioritization of investments in the context of requirements for distribution system renewal; (iii) advancement of business processes through convergence, replacement, or new investments in information systems technology; (iv) productivity improvements; (v) customer affordability; and (vi) a reasonable rate of return for shareholders.

Energy Revenue Components

Energy revenue projections are derived from price and load forecasts. Energy prices were forecasted using the OEB's April 2018 Regulated Price Plan Report which includes third party price forecasts from a reputable consulting firm. The 2019 Plan for RPP consumers assumes an average commodity price of 8.2 cents per kWh for 2019 which incorporates the OFHP. For non-RPP consumers, the 2019 Plan includes an average commodity price of 12.25 cents which is comprised of a spot price of 1.87 cents and a GA price of 10.38 cents. For non-RPP consumers who have opted-in as Class A GA, the 2019 Plan relies on the customer's peak demand factor to calculate the average GA price.

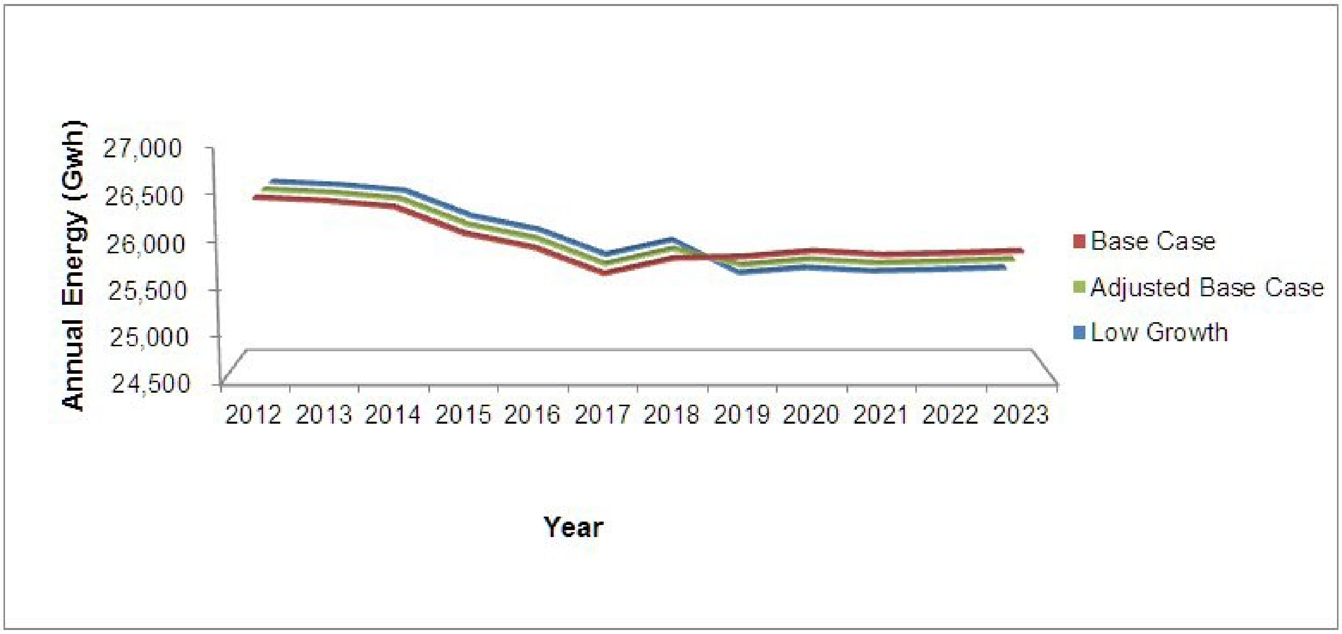
The 2019 Plan assumes energy revenue commodity price increases of approximately 2% per year. This assumption aligns with the OFHP, which establishes a framework to hold increases to the rate of inflation for a four-year period.

Load Forecast Methodology

The weather-normalized load forecasting process for the LDC rate zones utilizes multivariate regression load forecast models that are created at the customer class and rely on the following key variables: weather; calendar; and econometric variables to estimate the relationship between energy consumption, peak demand, and analytical factors and drivers. The main drivers used to derive the energy and load forecast include: actual historical energy consumption data; actual weather data; calendar data; GDP, CPI, population and employment data. The load forecast also includes projections of incremental energy savings to account for efficiency improvements from new end-use standards, building codes, and CDM programs.

The LDC utilized a third-party load forecasting solution to develop the five-year load forecast for each of the rate zones. The LDC then developed three load forecast scenarios: 1. Base Case; 2. Adjusted Base Case; and 3. Low Growth. The Base Case scenario relies on the above-mentioned consumption, weather, and economic data. The Adjusted Base Case scenario relies on the same data and economic drivers as the Base Case, but includes adjustments to certain General Service rate classes to reflect recent consumption and demand patterns. The Low Growth scenario assumes that the economic growth rates for population, income per capita, employment and GDP would be at 50% of the forecasted assumptions included in the Base Case. The LDC total energy consumption forecasts based on the three load forecast scenarios, are illustrated in Figure 1 below.

Figure 1: Load Forecast Scenarios (GWhs)

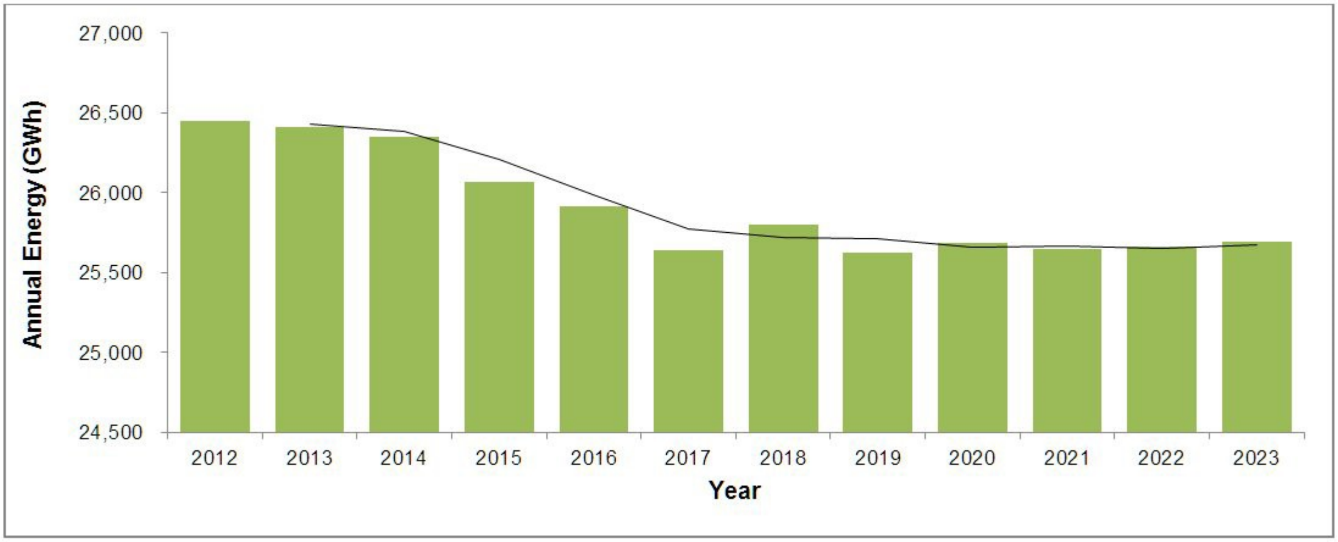


The Financial Plan incorporates a load forecast based on the Adjusted Base Case scenario. Under this recommended scenario, the consumption and demand outputs from the Itron Model were reviewed at the customer class level to assess the reasonability of the projected changes in consumption and demand over the forecast period.

Load Forecast Outcomes

The LDC total energy consumption forecasts, based on actual and forecasted weather normalization, are illustrated in Figure 2 below. Actual weather normalized consumption from 2012-2017 has decreased by an average of 0.6%, annually. Forecast weather normalized consumption is projected to increase by 0.6% in 2018. This is consistent with the IESO's 18-Month Outlook, published in June 2018, which forecasts a 1% increase in demand from 2017 to 2018. Conservation savings, energy efficient appliances and the introduction of new codes and standards seek to offset any increase in demand due to population growth and economic expansion. During the 2019 to 2023 period, total energy consumption is projected to remain relatively flat.

Figure 2: Energy Consumption by Year (GWhs)



The table below provides a breakdown of energy revenue per RZ over the five-year plan. The increase in energy revenue relative to the 2018 Plan is attributable to an increase in energy prices and an increase in forecast consumption.

Table 2: Energy Revenue per Rate Zone by Year ($MMs)

Energy Revenue	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**	**2023**
PowerStream RZ	960.6	987.2	1,009.2	1,024.4	1,042.4	**5,023.8**	1,061.0
Enersource RZ	818.8	869.2	883.2	891.1	901.0	**4,363.3**	911.2
Horizon Utilities RZ	513.3	535.4	547.2	554.9	564.4	**2,715.2**	574.2
Brampton Hydro RZ	465.8	492.4	504.8	515.5	527.4	**2,505.9**	540.1
Total Energy Revenue - 2019 Plan	**2,758.5**	**2,884.2**	**2,944.4**	**2,985.9**	**3,035.2**	**14,608.2**	**3,086.5**
Total Energy Revenue - 2018 Plan	2,664.7	2,664.9	2,688.9	2,713.5	2,738.4	**13,470.4**	NA
Difference	**93.8**	**219.3**	**255.5**	**272.4**	**296.8**	**1,137.8**	**NA**

Distribution Rate Setting

Distribution revenue for 2019 is based on the IR term / rate-setting approach of each respective predecessor utility to Alectra. The distribution revenue for each of the Brampton Hydro, Enersource and PowerStream rate zones is based on a Price Cap IR adjustment, which affords annual inflationary adjustments net of an expectation for productivity. The distribution revenue for the Horizon Utilities rate zone is based on the fourth annual adjustment to its Custom IR rate plan.

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Table 3: Rate Setting Methodology

	2019	2020	2021	2022	2023	2024	2025	2026
Horizon Utilities	**Custom IR**	**Price Cap**						
PowerStream	**Price Cap**							
Brampton	**Price Cap**							
Enersource	**Price Cap**							

The LDC filed an application with the OEB for 2019 EDR for all four rate zones on June 7, 2018 for an update to EDR and other charges, effective January 1, 2019.

The form of rate setting methodology for each distributor through the rebasing deferral period is illustrated in Table 3, above.

Subsequent to the rebasing deferral period, the LDC will file a Custom IR application for rates effective for the next five years (2027 to 2031). At that time, the merger savings/synergies will accrue to the benefit of customers through lower distribution rates.

Distribution Revenue Components

The 2019 forecast value for the inflation factor under Price Cap IR is assumed to be 1.6%, using the OEB forecasting model. Such model is based on 2017 Gross Domestic Product, IPI (such as Final Domestic Demand "GDP-IPI (FDD)"), and Average Weekly Earnings from Statistics Canada. The OEB will release the 2019 inflation factor value in November 2018. The Financial Plan assumes an inflation rate of 2.5% in 2020, and 2.1% in each of 2021, 2022 and 2023. The inflation rate forecast is based on the Bank of Canada's Monetary Policy Report, issued July 2018. The 2019 Budget includes a distribution rate increase of 1.3%, which incorporates the inflation factor of 1.6% less a "stretch" productivity factor for the Brampton, PowerStream and Enersource rate zones of 0.3%.

The 2019 Plan assumes ICM eligibility based on the rate setting methodology for each rate zone. Consequently, only the Horizon Utilities rate zone is ineligible for ICM in 2019. The table below identifies the ICM relief sought by rate zone, along with the expected revenue to be recovered based on the 2018 EDR Application Decision (the "Decision").

The OEB's Decision included narrative regarding the availability of ICM for post-MAADs distributors. The LDC filed its application for ICM recovery on the basis that, per OEB policy, the three tests that a distributor must meet are: i) materiality; ii) need; and iii) prudence. The LDC satisfied the materiality threshold and filed evidence to satisfy the tests for need and the prudence for each of the ICM projects.

However, in the Decision, the OEB applied a second, incremental materiality threshold. Rather than assess materiality at the project level, the OEB's assessment was at the consolidated distributor level. The OEB also indicated that sincea new methodology would likely have to evolve by way of policy proceeding, it would "use its judgment" to determine such threshold. The OEB did not provide its methodology for the incremental materiality assessment. The result was the approval of only 50% of ICM eligible capital projects for the PowerStream and Enersource rate zones.

The decrease in expected ICM revenue in 2019 and beyond, relative to the 2018 Plan, is as a result of using the 2018 Decision as guidance. Distribution revenue in 2019 includes a $3.3MM ICM recovery approved by the OEB for legacy Enersource, $2.4MM approved by the OEB in Alectra Utilities' 2018 EDR Application, and 50% of the ICM relief sought in the 2019 EDR application.

Further, the 2019 Plan assumes 50% recovery of ICM relief sought in 2020 to 2023. The LDC will need to reassess planned capital projects based on future OEB decisions, and determine the extent to which these projects will have to be deferred, as well as the resulting impact on customers (i.e., in terms of reliability, service quality).

Table 4: ICM per Rate Zone by Year ($MMs)

ICM Revenue	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**	**2023**
Prior Year ICM Recovery	**4.9**	**5.7**	**8.1**	**11.7**	**15.3**	**45.7**	**18.9**
Incremental ICM Relief Sought:							
PowerStream RZ	—	1.5	1.2	1.2	1.2	5.1	1.2
Enersource RZ	—	0.9	1.2	1.2	1.2	4.5	1.2
Horizon Utilities RZ	—	—	1.2	1.2	1.2	3.6	1.2
Brampton Hydro RZ	—	—	—	—	—	—	—
Total Incremental Relief	**—**	**2.4**	**3.6**	**3.6**	**3.6**	**13.2**	**3.6**
Total ICM Revenue	**4.9**	**8.1**	**11.7**	**15.3**	**18.9**	**58.9**	**22.5**
Less: 50% Recovery Assumption	—	(1.2)	(3.0)	(4.8)	(6.6)	(15.6)	(8.4)
Total ICM - 2019 Plan	**4.9**	**6.9**	**8.7**	**10.5**	**12.3**	**43.3**	**14.1**
Total ICM - 2018 Plan	7.0	10.3	16.0	20.3	23.6	77.2	N/A
Difference	**(2.1)**	**(3.4)**	**(7.3)**	**(9.8)**	**(11.3)**	**(33.9)**	**N/A**

Distribution revenue in 2019 also includes a reduction in revenue of $2.3MM due to the impact of the OEB's decision on the treatment of Alectra Utilities' capitalization policy change for ratemaking purposes. Alectra Utilities filed the capitalization policy change that it was required to make under IFRS, as a result of the amalgamation, in the 2018 EDR Application. In a partial decision issued in December 2017, the OEB required Alectra Utilities to establish deferral accounts for each of the Brampton, Enersource, and Horizon Utilities rate zones. In the 2018 EDR Application Decision, the OEB has flowed through this impact for the Horizon Utilities rate zone through Horizon Utilities' ESM, such that at most customers would get 50% of the reduced OM&A resulting from the capitalization policy change for 2019.

The LDC is also permitted to recover lost distribution revenue from differences between the CDM assumption within a distributor's OEB-approved load forecast and actual CDM results at a customer rate class level. This regulatory mechanism ensures that the delivery of CDM programs by distributors do not act as a disincentive in meeting prescribed CDM targets. LRAMVA revenue is recognized quarterly, based on preliminary CDM results provided by the IESO. Adjustments, if any, are made when final CDM results are published by the IESO. This approach results in the recognition of revenue in the year in which the CDM savings occur, where the revenue recovery partially offsets the lost revenue resulting from CDM programs. The table below provides LRAMVA per rate zone over the five-year plan. The increase in LRAMVA revenue relative to the 2018 Plan is due to higher than expected savings achieved in 2017 based on final verified savings by the IESO and higher than anticipated savings in 2018 based on preliminary results.

Table 5: LRAMVA per Rate Zone by Year ($MMs)

LRAM Revenue	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**	**2023**
PowerStream RZ	2.8	3.4	3.1	3.8	4.4	17.5	5.1
Enersource RZ	2.7	2.4	2.7	2.8	3.1	13.7	3.3
Horizon Utilities RZ	2.2	0.9	1.0	1.1	1.2	6.4	1.2
Brampton Hydro RZ	0.6	1.1	1.2	1.5	1.6	6.0	1.7
Total LRAM - 2019 Plan	**8.3**	**7.8**	**8.0**	**9.2**	**10.3**	**43.6**	**11.3**
Total LRAM - 2018 Plan	5.0	5.8	6.5	7.5	8.5	33.3	N/A
Difference	**3.3**	**2.0**	**1.5**	**1.7**	**1.8**	**10.3**	**N/A**

The LDC completes an annual review of each non-residential customer's rate classification to determine whether the customer should be assigned to a different rate class. The distribution revenue budget incorporates the impact of the reclassification of 1,321 customers across Alectra Utilities' four rate zones, resulting in a reduction in distribution revenue in 2019 of $1.3MM. The majority of these general service customers will be assigned to a lower rate class as a result of reduced consumption and demand, primarily driven by conservation and demand management initiatives. The 2019 budget assumes 50% of the annual impact of the customer reclassification will impact distribution revenue in 2019, based on the assumption that the reclassification exercise will be completed mid-year in 2019. The 2020 to 2023 distribution revenue budget assumes an average reduction of $2.7MM per year due to customer reclassifications.

Distribution revenue for the Horizon Utilities Rate Zone is based on the proposed revenue requirement update included in the 2019 EDR Application. The reduction in revenue requirement compared to the Custom IR application is primarily due to a decrease in working capital, as a result of changes to cost of power flow through costs. These include: i) the RPP reductions effective May 1; ii) an update to the Smart Metering Entity Charge, as approved by the OEB on March1, 2018; and iii) a decrease to the Rural Remote Rate Protection rate, as approved by the OEB on June 22, 2017. A further update to revenue requirement will be completed when the OEB releases the cost of capital parameters for 2019, anticipated November 2018.

The forecast number of LDC customers at year-end is 1,006,516, which represents a 1.4% growth rate over the 2018 forecast. This projection is in-line with the 2018 Plan, driven mainly by higher growth rates in the Brampton and PowerStream rate zones. These customer growth projections are estimated using linear regression models that incorporates population forecasts from the Conference Board of Canada for the Toronto and Hamilton Metropolitan Areas.

The table below provides a breakdown of distribution revenue per rate zone over the five-year plan. The decrease in distribution revenue relative to the 2018 Plan is mainly attributable to lower ICM revenue and the impact of the OEB's decision on the change in capitalization policy for Alectra. Both items were impacted by the OEB's Decision in Alectra's 2018 EDR Application.

Table 6: Distribution Revenue per Rate Zone by Year ($MMs)

Distribution Revenue	2018	2019	2020	2021	2022	Total	2023
PowerStream RZ	206.7	210.4	214.0	221.2	228.5	1,080.8	236.0
Enersource RZ	133.9	135.9	139.5	143.2	147.1	699.6	151.1
Horizon Utilities RZ	111.4	112.6	113.9	117.6	121.5	577.0	125.4
Brampton Hydro RZ	76.6	80.4	83.5	86.5	89.5	416.5	92.6
Total Distribution Revenue - 2019 Plan	**528.6**	**539.3**	**550.9**	**568.5**	**586.6**	**2,773.9**	**605.1**
Total Distribution Revenue - 2018 Plan	526.7	543.0	563.4	580.8	598.6	2,812.5	NA
Difference	**1.9**	**(3.7)**	**(12.5)**	**(12.3)**	**(12.0)**	**(38.6)**	**NA**

Conservation and Demand Management

With no government funded conservation programs planned for 2021 and beyond, the 2019 Plan does not contemplate any programs beyond 2020. There is some risk that these programs could be terminated earlier to support the electricity bill reduction targets of the provincial government.

The 2019 Plan further assumes that the underlying internal CDM cost structure is eliminated coterminous with the end of the current term of government funding. Based on the terms of the IESO contract, Alectra has assumed that any windup costs including severance are eligible CDM program costs. However, Alectra would have to manage such costs within the overall program budget.

The consolidated six-year CFF (2015-2020) CDM target for LDC comprises 1,605 GWh of energy savings within an approved IESO-funded budget of $414.8MM. On June 28, 2017, Alectra submitted a joint CDM Plan to the IESO that included Collus PowerStream and Erie Thames Powerlines, resulting in a total joint energy savings target of 1,649 GWh and a joint budget of $426.0MM. The CDM Plan received IESO approval effective October 1, 2017.

The LDC submitted a second joint CDM plan to the IESO in September, 2018. The overall energy savings targets and budgets remain the same, but some CDM programs (e.g., Heating & Cooling) will no longer be offered by LDC, and will instead be delivered by the IESO, due to the success LDC has achieved and is expected to continue achieving in LDC continues to provide Collus PowerStream with a fully integrated turn-key CDM delivery solution, and to deliver certain CDM programs on behalf of Erie Thames Powerlines to its customers.

There are two funding models available under CFF: FCR and P4P. Under the FCR model, the IESO reimburses all eligible costs and expenses incurred by LDC in the design, development and delivery of its CDM plan. Under P4P, the IESO compensates LDC based on a pre-specified value for each verified kilowatt hour of electricity savings achieved. All legacy distributors to LDC had been delivering CDM plans under FCR. Retrofit programs provide commercial and industrial customers with incentives for replacing inefficient equipment with high efficiency equipment, while the Process & Systems upgrades program provides financial support and/or incentives for the implementation and replacement of energy efficiency projects and system optimization projects for facilities that are intrinsically complex and capital. LDC now delivers all Retrofit projects via P4P funding.

While there are no performance nor cost efficiency incentives for programs delivered under the P4P funding option, it does provide an opportunity to generate net revenue based on efficient program delivery (i.e., retaining the difference between program delivery costs and the $0.22 per kWh payment from the IESO noted above).

Legacy-Enersource had been delivering the Retrofit Program and the Process and Systems Upgrade Program under the P4P funding option since 2015. For the period 2015-2017, $1.5MM of margin from P4P funding has been recognized for shareholders, for programs delivered in the legacy-Enersource territory.

As indicated in the Joint CDM Plan, Alectra CDM will be delivering the Retrofit Program under the P4P option to all customers (eventually including those in the Guelph Hydro service territory), and is budgeting to generate an additional $0.6MM in P4P net margin for the benefit of shareholders, over the course of the remaining CDM framework. This amount is a conservative estimate, and does have the potential to rise to a value much higher. However, the design of the P4P funding model, which is applied on an IRR basis for a six year portfolio of thousands of projects, creates a significant amount of uncertainty in forecasting the final net margin for the CFF, and Alectra CDM is reluctant to set expectations any higher than the figure above.

The following table provides a comparison of revenues from CDM program between the 2019 Plan and 2018 Plan.

Table 7: CDM Revenue by Year ($MMs)

Other Revenue	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**	**2023**
2019 Plan	13.6	0.3	0.3	—	—	14.2	—
2018 Plan	8.2	1.5	1.3	0.3	—	11.3	NA
Difference	**5.4**	**(1.2)**	**(1.0)**	**(0.3)**	**—**	**2.9**	**NA**

Other Revenue

Other revenue is mainly comprised of CDM revenue (thus incorporating the revenue in Table 7), regulated customer service charges, and service revenues. The CDM revenue plan is outlined in the previous section. Customer service charges are generally forecast based on historical trends including projected customer growth across rate zones. [redacted]

The table below provides a comparison of other revenue between the 2019 Plan and 2018 Plan. The differences are analyzed in Section 4.0.

Table 8: LDC Other Revenue by Year ($MMs)

Other Revenue	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**	**2023**
2019 Plan	46.5	32.5	26.5	27.1	27.2	159.8	27.1
2018 Plan	40.4	30.4	32.1	29.9	29.7	162.5	NA
Difference	**6.1**	**2.1**	**(5.6)**	**(2.8)**	**(2.5)**	**(2.7)**	**NA**

Residential and Small Commercial Customers - Disconnection Moratorium

Generally, regulated credit policies reasonably mitigate low concentration risks such as residential and small commercial credit risks. However, an economic decline, local or otherwise, can place upward pressure on credit risk; particularly as it relates to higher concentrations of larger industrial customers described further below. Regulatory constraints on LDC's ability to take action to encourage customer payment (e.g. - restrictions on disconnections, economic penalties such as disconnect/ reconnect fees, etc.), as well as rising electricity costs, will continue to have an unfavourable impact on customer credit risk and credit losses. Any change in the experience of annual credit losses are recoverable through rates, on a prospective basis, following a re-basing application. Alectra remains exposed to largely immitigable credit risk through its re-basing deferral period.

The OEB amended the licenses of all electricity distributors to permanently prohibit disconnecting residential consumers for reason of non-payment during the winter period. The OEB established a permanent Disconnection Ban Period from November 15 of one year until April 30 of the next calendar year. The expected result of the disconnection moratorium is increased credit losses of $0.4MM per year and a reduction in disconnection/ reconnection revenues of $1.2MM per year. These financial challenges should generally be resolved prospectively in future rebasing applications, which provide for a recovery of an average level of historical credit losses and adjustment to distribution rate revenue. However, increases in the average level of credit losses will ultimately be socialized across all customer classes. The LDC has no apparent regulatory recourse to recover increased credit losses arising from OEB Code changes between re-basing applications.

Ontario Energy Board Report: Review of Customer Rules for Utilities

The OEB released a Report for comment on September 7, 2018 regarding proposed changes to the Customer Service Rules. Alectra is working with the Coalition of Large Distributors to respond to the proposed regulation which includes: extended payment timelines; an additional collections reminder notices; increased time lines from customer invoice generation to when the service location may be disconnected for non-payment; and the elimination/ limitation of certain collections-related charges. If accepted as proposed, it is estimated that Alectra would experience increased credit losses of $0.3MM annually and a reduction in disconnection/ reconnection revenues of $1.3MM per year. These assumptions have been incorporated into the 2019 Plan.

OM&A Expenses

The average non-labour OM&A inflation rate is assumed to be 1.5% per year. Inflation rates are based on a weighted average annual inflation rates experienced in Canada between January 2016 and August 2018.

On June 28, 2017, a union representation vote was held and unionized employees selected the PWU as their new collective bargaining agent. Alectra commenced collective bargaining with PWU on September 26, 2017 and at the time of preparation of the 2019 Plan Management remains actively engaged in negotiations through the collective bargaining committee. The 2019 Plan assumes annual union labour inflation based on a negotiations mandate approved by the Board of Directors.

Annual general non-union labour inflation is assumed at 2.3%, plus an additional 3.0% annually for those employees below the mid-point job rate to permit progression towards the job rate; subject to the results of annual individual employee performance review outcomes.

The benefit rates included in the 2019 Plan are summarized below for the years 2019 to 2023:

- CPP, EI, WSIB premiums and EHT are based on the Government of Canada rates. Recent CPP changes result in an incremental $0.2MM per year commencing in 2018;
- OMERS rates range from 9% to 14.6% per year, based on yearly maximum pensionable earnings with corresponding annual expenses inflated at approximately 2.6% per year based on union and non-union wage inflation assumptions identified above; and
- All fringe benefits such as extended health benefits, life insurance, long-term disability, etc. are based on the negotiated changes as a result of the policy harmonization process. The benefits harmonization process has contributed favourably compared to the 2018 Plan and the savings are further outlined in Section 4.0.

The budget assumes a 3% vacancy rate within LDC, which is consistent with pre-merger experience.

Other expenses such as safety equipment, repairs and maintenance, etc. are based on the historical experience of each of LDC's predecessors.

The 2019 Plan introduces additional operating expenditures corresponding to growing customer demands and system reliability in Network Operations, statutory requirements in Finance and Regulatory, and investments in renewable energy initiatives. These expenditures are further detailed in the analysis of operating expenditures in Section 4.0.

Innovation Centre

Alectra has an Advanced Planning organization that is an incubator for conceptualizing next generation energy solutions and develop innovative concepts for next generation utility and energy provider offerings such as: residential energy storage solutions; Blockchain technology; Advantage Planet, which focuses on reducing the demands on the electricity grid during peak hours; Virtual Power Planting; and microgrid as a service.

This organization provides research and development through to commercialization. It has been the intention of Alectra to create a more focused and resourced centre for Advanced Planning. The proposed merger with Guelph Hydro has advanced the planning for such an Innovation Centre based on commitments within the ongoing negotiation. This has been branded as the GRE&T centre.

The GRE&T centre will focus on identifying, evaluating, and developing emerging, green, and customer friendly energy solutions that will drive Alectra to become a next generation utility. The initial focus will be on the residential customer base with planned expansion to commercial and agricultural customer base(s).

The 2019 Plan assumes no capital or operating expenditures for the GRE&T centre. The business model requires further development regarding the scope, cost structure and potential sources of financing beyond the budget for the Advanced Planning organization including tax credits and government incentives. The incremental financial impact of the GRE&T centre, beyond the five-year plan for current Advanced Planning resources, will be provided once fully developed.

The following tab provides a summary of the financial impact of the GRE&T centre should the merger with Guelph Hydro be approved:

Table 9: GRE&T centre financial impact ($MMs)

	2019	2020	2021	2022	2023	Total
Revenue	**0.6**	**0.6**	**0.4**	**0.1**	**—**	**1.7**
Labour expenditures	0.8	1.1	1.2	1.2	1.2	**5.5**
Non-Labour expenditures	1.0	1.3	1.1	0.8	0.8	**5.0**
Total operating expenditures	**1.8**	**2.4**	**2.3**	**2.0**	**2.0**	**10.5**
Gross Margin fav (unfav)	**(1.2)**	**(1.8)**	**(1.9)**	**(1.9)**	**(2.0)**	**(8.8)**

Depreciation and Derecognition

Depreciation of PP&E is recognized on a straight-line basis over the estimated useful life of each component of PP&E and intangible assets. Depreciation methods and useful lives are reviewed at each financial year-end and any changes are adjusted prospectively. The estimated useful lives are as follows:

Property, plant and equipment	
Buildings and Fixtures	10 to 60 years
Distribution System	15 to 40 years
Other PP&E	3 to 20 years
Intangible assets	
Land rights	Indefinite
Computer software	3 to 10 years
Capital contributions	16 to 45 years

The following table provides a summary of depreciation by major asset category in the LDC:

Table 10: 2019 - 2023 LDC depreciation summary by major category ($MMs)

	2018	2019	2020	2021	2022	Total	2023
Distribution assets	104.6	112.7	120.0	128.2	134.5	**600.0**	139.2
Computer software	14.8	18.1	20.5	21.3	21.9	**96.6**	22.1
Buildings, office furniture and equipment	5.8	6.5	6.5	6.5	6.0	**31.3**	5.6
Rolling stock / fleet	4.6	4.5	5.0	5.2	5.4	**24.7**	5.7
Computer hardware	3.7	2.5	2.3	2.5	3.0	**14.0**	3.6
Other assets	1.8	1.8	2.3	2.9	2.8	**11.6**	2.9
Tools, shop, and garage equipment	1.2	1.1	1.2	1.2	1.3	**6.0**	1.3
Land and buildings	0.5	0.5	0.5	0.5	0.5	**2.5**	0.5
Stores equipment	0.1	0.1	0.1	0.1	0.1	**0.5**	0.1
Land rights	—	—	—	—	—	**—**	—
Deferred revenue	(8.9)	(11.9)	(13.2)	(14.1)	(15.1)	**(63.2)**	(15.9)
Capital contributions	(5.5)	(5.5)	(4.4)	(4.2)	(4.2)	**(23.8)**	(5.5)
Total depreciation expenditures (2019 Plan)	**122.7**	**130.4**	**140.8**	**150.1**	**156.2**	**700.2**	**159.6**
Total depreciation expenditures (2018 Plan)	**121.5**	**127.2**	**132.1**	**138.7**	**144.6**	**664.1**	**N/A**
Total depreciation expenditures (difference)	**1.2**	**3.2**	**8.7**	**11.4**	**11.6**	**36.1**	**N/A**

Section 4.0 provides additional information on the plan over plan variances in Table 10.

Derecognition expense has been included in the 2019 Plan using historical information and other indications of asset impairments. In addition, redundant IT systems eliminated from convergence projects will be derecognized for accounting purposes with associated losses to the extent of their remaining unamortized net book value. The 2019 Plan provides for the derecognition of assets as follows:

Table 11: Derecognition Expense ($MMs)

MIFRS	2018	2019	2020	2021	2022	Total	2023
Distribution Assets Derecognition Expense	5.8	5.9	6.0	6.1	6.1	**29.9**	6.2
IT Asset Derecognition Expense						**—**	
Customer Information System		*0.4*	—	—	—	***0.4***	—
Integrated Operating System		—	*0.2*	—	—	***0.2***	—
Supervisory control and data acquisition		*0.9*	—	—	—	***0.9***	—
Total IT Asset Derecognition Expense	**—**	**1.3**	**0.2**	**—**	**—**	**1.5**	**—**
Cityview vacant land	—	*(2.5)*	—	—	—	***(2.5)***	—
Stoney Creek operation centre	—	—	*(4.3)*	—	—	***(4.3)***	—
Total Derecognition Expense (2019 Plan)	**5.8**	**4.7**	**1.9**	**6.1**	**6.1**	**24.6**	**6.2**
Total Derecognition Expense (2018 Plan)	**6.4**	**7.9**	**6.6**	**6.4**	**6.4**	**33.7**	**N/A**
Total Derecognition Expense (difference)	**(0.6)**	**(3.2)**	**(4.7)**	**(0.3)**	**(0.3)**	**(9.1)**	**N/A**

Derecognition expenditures are consistent relative to the 2018 Plan with the notable exception in 2019 and 2020; primarily attributable to the gain on sale of the Stoney Creek operations centre and the vacant land adjacent to the Cityview corporate office.

Transfer Pricing - Shared Services Allocations

Alectra has completed a transfer pricing study for purposes of inter and intra company service charges. The results of the study are incorporated into the 2019 Plan. The transfer pricing study has no impact on the consolidated 2019 Plan results compared to the 2018 Plan but has modest implications to the financial plans of individual business units.

Tax

The combined federal and provincial income tax rate is assumed at its present level of 26.5%.

Under MIFRS, timing differences between accounting and cash taxes are recorded as a regulatory asset/liability for deferred taxes rather than as deferred tax expense. However, this treatment does not included timing differences that are attributable to shareholders. For these items, the impact of the change in timing differences is recorded to deferred tax expense. These timing differences include:

- the value of capital cost allowance arising from the increase in undepreciated capital cost attributable to the acquisition of the former Hydro One Brampton Networks Inc.; and
- severance costs realized in the year.

As a result of the MIFRS treatment of timing differences, the MIFRS effective tax rate for 2019 to 2023 is as follows:

Table 12: MIFRS effective tax rate ($MMs)

	2019	2020	2021	2022	2023
MIFRS net income before tax	121.0	140.2	138.9	145.7	149.1
Statutory Tax Rate	26.5%	26.5%	26.5%	26.5%	26.5%
Tax expense at statutory rate	32.1	37.2	36.8	38.6	39.5
Increase (decrease) resulting from:					
Depreciation / CCA difference	(24.9)	(21.5)	(13.4)	(12.6)	(12.4)
Other	1.0	0.8	0.6	0.7	0.9
Income tax expense	8.2	16.5	24.0	26.7	28.0
Effective income tax rate	6.8%	11.8%	17.3%	18.3%	18.8%

In 2019 and 2020, the MIFRS effective tax rate is significantly lower than the statutory rate primarily due to the accelerated capital cost allowance deduction on software transition projects. From 2021 to 2023, the capital cost allowance related to software normalizes resulting in the MIFRS effective tax rate being closer to the statutory rate.

[redacted]

Balance Sheet Items (Accounts Receivable, Unbilled Revenue, PP&E, and Accounts Payable)

The projected balances for accounts receivable, unbilled revenue, accounts payable and PP&E at year end are based on a few drivers, namely: revenue growth; electricity sales; cost of sales; and the capital expenditure plan.

Accounts receivable is trending upwards over the plan period in conjunction with distribution revenue and electricity sales. PP&E is trending upward over the plan period due to increased in-service assets from the capital program which is described in more detail in section 5.0. Accounts Payable trends upwards over the plan period corresponding to increased cost of power and the capital plan.

The 2019 Plan utilizes electricity sales, cost of power, and O&M costs to determine its working capital requirements. The main drivers used to derive capital requirements are provided by the Asset Management team, outlined further in section 5.1.

The balance sheet supports compliance with debt covenants such as debt to total capitalization ratios.

Post-Employment Benefits

The net obligation with respect to post-employment benefits are calculated based on an actuarial valuation performed in 2018. The obligation estimates the post-employment benefits that Alectra anticipates providing to employees and their beneficiaries subsequent to employment, earned in return for their service in the current and prior periods. The obligation is discounted using the current interest yield on high quality debt instruments with duration similar to the duration of the plan as determined by an independent actuary.

The following table provides the actuarial assumptions underlying the post-retirement benefit obligation.

Table 13: Actuarial assumptions underlying the post-retirement benefit obligation

	(%)
Discount rate	3.40%
Rate of compensation increase	3.30%
Medical benefits cost escalation	5.98%
Dental benefits cost escalation	4.50%

The following table provides the estimated impact on the defined benefit obligation if the primary actuarial assumptions underlying the valuation increased or decreased by 1% are below.

Table 14: Sensitivity analysis on 2019 Post-Employment Benefits

($MM)	**$**
Discount rate:	
1% increase	(9.0)
1% decrease	(11.0)
Medical and dental benefits cost escalation:	
1% increase	7.0
1% decrease	6.0

Leases

New standard IFRS 16 - Leases is effective for annual reporting periods beginning on or after January 1, 2019. Under IFRS 16, the discounted value of future minimum lease payments under operating leases are recognized on balance sheet as right of use assets with a corresponding lease liability. Under the previous standard, periodic payments under operating leases were recognized as operating expenses as incurred.

Under the new standard, lease payments are discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, then the lessee's incremental borrowing rate is used. Interest is imputed on the lease liability at the discount rate and recorded as an expense. The lease liability is reduced for lease payments. The related right-of-use asset is depreciated in accordance with the remaining term of the operating lease contract.

The impact to each entity as at December 31, 2019 under MIFRS using the full retrospective approach is as follows:

Table 15: IFRS 16-Leases 2019 impact per entity

($MMs) - fav (unfav)	AUC Shared		[redacted]
Impact on operating results			
Impact to EBITDA	0.9		
Impact to EBT	—		
Impact on balance sheet			
Impact to equity	(4.0)		
Right of use asset	13.5		
Lease liability	17.5		

Guelph Merger

On October 19, 2018, Alectra Utilities and Guelph Hydro received approval from the OEB for the amalgamation of Alectra Utilities and Guelph Hydro into a combined LDC that will continue as Alectra Utilities. The 2019 Plan excludes the potential implications of a merger occurring in 2019 with the notable exception of inclusion in the presentation of Net income and dividends in Sections 1.0 and 4.0.

[redacted]

[redacted]

Rate Base

Rate base represents the value of investments that Alectra is able to earn a rate of return. Rate base is approved by the OEB upon a rebasing application and calculated and provided to the OEB as part of the annual reporting requirements. The following table provides the calculation of rate base from 2017 to 2023 for the Local Distribution Company:

Table 17: Alectra rate base calculation by year ($000s)

	2017 Actual	2018 Forecast	2019 Plan	2020 Plan	2021 Plan	2022 Plan	2023 Plan
Cost of power	2,489.7	2,758.5	2,884.1	2,944.4	2,985.9	3,035.2	3,086.5
Operating expenses	231.5	243.4	247.8	224.4	228.3	232.0	238.7
Total Cost of Power and Operating Expenses	2,721.2	3,001.9	3,131.9	3,168.8	3,214.2	3,267.2	3,325.2
Working capital allowance %	10.66%	10.66%	10.66%	10.66%	10.66%	10.66%	10.66%
Working capital allowance ($MM)	290.1	320.0	333.9	337.8	342.6	348.3	354.5
PP&E							
Opening balance - regulated PP&E (NBV)	2,376.4	2,505.4	2,652.3	2,772.1	2,908.4	3,031.0	3,156.2
Closing balance - regulated PP&E (NBV)	2,505.4	2,652.3	2,772.1	2,908.4	3,031.0	3,156.2	3,281.8
Average regulated PP&E	2,440.9	2,578.9	2,712.2	2,840.3	2,969.7	3,093.6	3,219.0
Rate Base	**2,731.0**	**2,898.9**	**3,046.1**	**3,178.1**	**3,312.3**	**3,441.9**	**3,573.5**

The following table provides a summary of the OEB approved rate base by rate zone for the Local Distribution Company:

Table 18: Summary of OEB approved rate base by legacy utility ($MMs)

Rate Zone	**Last rebasing (approval) year**	**Approved Rate Base**
Enersource Rate Zone	2013	623
Horizon Rate Zone	2017	521
Brampton Rate Zone	2015	405
PowerStream Rate Zone	2017	1,083
Total		**2,632**

[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

2.4 Synergies and Transition Costs

The 2019 Plan incorporates synergies and transition costs provided in the 2018 Plan but adjusted based on Table 27 and corresponding analysis below.

In total, Alectra will deliver approximately $260.8MM of net cash savings (pre-tax) over the six year period from 2018-2023, which compares unfavourably to the 2018 Plan by $33.3MM, and unfavourably by $37.9MM to the merger Business Plan.

2019 Plan vs. Business Plan

The $37.9MM unfavourable variance to the merger Business Plan is principally attributable to: i) lower operating synergies-labour ($67.1MM); ii) higher capital transition costs ($66.9MM); partially offset by iii) higher operating synergies-non-labour ($87.9MM); iv) higher capital synergies ($7.3MM); and v) lower operating transition costs ($0.9MM).

Labour operating synergies compare unfavourably to the merger Business Plan by $67.1MM, principally attributable to: i) an increase in permanent positions; ii) higher than anticipated increases to management wage inflation; and iii) higher than anticipated costs for union wage harmonization.

Capital transition costs compare unfavourably to the merger Business Plan by $66.9MM, primarily due to increased expenditure related to the: i) ERP, CIS and GIS consolidation; ii) facilities renovations at Derry Rd, John St, and Cityview, to accommodate for department/staff relocations, Control Room and Call Centre consolidation, and other integration project initiatives; iii) various IT system consolidation initiatives; and iv) new Operations voice radio system.

Non-labour operating synergies compare favourably to the merger Business Plan by $87.9MM, principally attributable to: i) favourable financing costs resulting from a reduction to forecast yield on the $675MM debenture issuance; ii) favourable PowerStream rate application decision; iii) increased Treasury and insurance related synergies; iv) consolidation of membership commitments for OEA, EDA, OEN, CEA and My safe Work organizations; v) favourable locate costs resulting from implementation of best practices to all Alectra service territories; vi) benefit plan amalgamation savings on pooled benefit and health and dental costs; partially offset by: vii) increased costs related to the mandate to operate new Derry Rd. and John St. cafeteria's; viii) Increase in 407 ETR usage; and ix) reduction in volume discounts.

Capital synergies compare favourably to the merger Business Plan by $7.3MM, primarily due to: i) reduction to capital expenditures corresponding to canceled Facilities initiatives; ii) higher IT synergies due to timing of synergy projects; partially offset by iii) lower recognition of direct labour synergies from avoided headcount positions.

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2019 Plan vs. 2018 Plan

The 2019 Plan incorporates a net reduction in synergies of $1.1MM, with operating synergies comparing unfavourably to the 2018 Plan by $11.5MM. The capital synergies compare favourably to the 2018 Plan by $10.4MM.

Management closely reviews synergies and transition costs on a monthly basis and provides corresponding reports the Board of Directors on a quarterly basis.

Operating and capital synergies and transition costs are further analyzed below.

Table 27: Operating and Capital Synergies ($MMs)

2019 Plan Synergies	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Operating synergies (Non-Labour)	21.9	21.0	24.5	25.5	25.8	25.8	144.5
Operating synergies (Labour - FTE Reductions)	16.3	22.1	26.5	27.0	27.4	27.8	147.1
Operating synergies (Labour - On-going cost increase)	(5.6)	(8.7)	(8.9)	(9.1)	(9.3)	(9.5)	(51.1)
Capital synergies	49.2	19.4	15.6	23.0	13.2	7.5	127.9
Total Synergies	*81.8*	*53.8*	*57.7*	*66.4*	*57.1*	*51.6*	*368.4*
Operating transition costs	4.9	15.8	0.2	0.2	—	—	21.1
Capital transition costs	45.1	34.8	3.6	3.0	—	—	86.5
Total Transition Costs	*50.0*	*50.6*	*3.8*	*3.2*	—	—	*107.6*
Total Net Synergies	**31.8**	**3.2**	**53.9**	**63.2**	**57.1**	**51.6**	**260.8**

2018 Plan Synergies	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Operating synergies (Non-Labour)	18.2	16.9	18.9	18.7	18.7	18.7	110.1
Operating synergies (Labour - FTE Reductions)	17.9	24.9	31.2	33.1	33.6	33.6	174.3
Operating synergies (Labour - On-going cost increase)	(5.3)	(5.3)	(5.4)	(5.4)	(5.5)	(5.5)	(32.4)
Capital synergies	21.1	31.7	21.0	27.7	8.0	8.0	117.5
Total Synergies	*51.9*	*68.2*	*65.7*	*74.1*	*54.8*	*54.8*	*369.5*
Operating transition costs	18.3	0.7	0.2	0.2	—	—	19.4
Capital transition costs	40.4	15.6	—	—	—	—	56.0
Total Transition Costs	*58.7*	*16.3*	*0.2*	*0.2*	—	—	*75.4*
Total Net Synergies	**(6.8)**	**51.9**	**65.5**	**73.9**	**54.8**	**54.8**	**294.1**

Differences	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Operating synergies (Non-Labour)	3.7	4.1	5.6	6.8	7.1	7.1	34.4
Operating synergies (Labour - FTE Reductions)	(1.6)	(2.8)	(4.7)	(6.1)	(6.2)	(5.8)	(27.2)
Operating synergies (Labour - On-going cost increase)	(0.3)	(3.4)	(3.5)	(3.7)	(3.8)	(4.0)	(18.7)
Capital synergies	28.1	(12.3)	(5.4)	(4.7)	5.2	(0.5)	10.4
Total Synergies	*29.9*	*(14.4)*	*(8.0)*	*(7.7)*	*2.3*	*(3.2)*	*(1.1)*
Operating transition costs	(13.4)	15.1	—	—	—	—	1.7
Capital transition costs	4.7	19.2	3.6	3.0	—	—	30.5
Total Transition Costs	*(8.7)*	*34.3*	*3.6*	*3.0*	—	—	*32.2*
Total Differences	**38.6**	**(48.7)**	**(11.6)**	**(10.7)**	**2.3**	**(3.2)**	**(33.3)**

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Operating Synergies

Operating synergies represent payroll and non-payroll cost savings in the amount of $240.5MM over the six year period from 2018-2023. The payroll savings result from redundant positions largely in administration and back-office functions, as well as the reduction of staff dedicated to legacy IT systems that are no longer required.

Non-payroll savings principally comprise of the financing cost savings corresponding to a lower interest rate on an inaugural 2017 $675MM debenture issuance, the elimination of duplication within business processes across Alectra, and the adoption of best practices including:

- Reduction of third party costs (e.g. consulting, legal etc.);
- Consolidation of contracts and services;
- Volume discounts;
- Software licensing and maintenance; and
- Consolidation of systems.

Non-labour operating synergies increased $34.4MM over the 2019 Plan, as compared to the 2018 Plan, principally attributable to:

- Reduction in the Jane Street office lease;
- Favourable financing costs resulting from a reduction to forecast yield on the $675MM debenture issuance resulting in $9.3MM of annual pre-tax savings relative to the prior plan;
- Favourable PowerStream rate application decision;
- Consolidation of membership commitments for OEA, EDA, OEN, CEA and My safe Work organizations;
- Benefit plan amalgamation savings on pooled benefit and health and dental costs;
- Favourable locate costs resulting from implementation of best practices to all Alectra service territories;
- Increase in Treasury synergies resulting from: interest savings on debt issuance to purchase Brampton Hydro, interest savings from reduction in float balances related to convergence to one bank, insurance synergies, reduced letter of credit and rating agency fees, and launch of commercial paper program providing more favourable short-term financing rates.

Partially offset by:

- Increased costs related to the mandate to operate new Derry Rd. and John St. cafeteria's;
- Increase in 407 ETR usage; and
- Reduction in volume discounts.

Labour operating synergies decreased by $45.9MM over the 2019 Plan, as compared to the 2018 Plan, principally attributable to:

- Increase in new permanent positions;
- Higher than anticipated increases to management wage inflation; and
- Higher than anticipated costs for union wage harmonization.

Operating Transition Costs

Operating transition costs represent expenditures relating to people, processes, and technology. Alectra projects $21.1MM in transition costs over the six year period from 2018-2023. Operating transition costs include:

- Voluntary separation packages and relocation;
- IT system migration and integration costs;
- Re-branding and communication tool integration; and
- Third-party costs.

Operating transition costs increased by $1.7MM over the 2019 Plan, as compared to the 2018 Plan, principally attributable to:

- ERP convergence costs were updated to incorporate the latest cost projections. As a result, operating transition costs for the ERP project are $0.9MM higher than the 2018 Plan;
- CIS convergence costs were updated to incorporate the latest cost projections. As a result, operating transition costs for the CIS project are $0.5MM lower than the 2018 Plan; and
- Higher than anticipated integration project costs.

Capital Synergies

Capital synergies represent avoided capital investments of $127.9MM over the six year period from 2018-2023. These savings primarily represent avoided IT costs otherwise necessary in the absence of the merger.

Areas of savings include:

- Elimination of IT costs due to converged IT Systems (e.g. programming, maintenance and license fees from legacy systems);
- Anticipated volume discounts for inventory and third party contractors;
- Rationalization of fleet and equipment across the three operating regions of LDC;
- Elimination of duplicated programming costs due to regulatory compliance or changes in regulation (e.g. CIS programming for billing changes); and
- Reduction of labour costs from the elimination of future hires and best practice adoption of work methods.

Capital Synergies increased by $10.4MM over the 2019 Plan, as compared to the 2018 Plan, principally attributable to:

- Recognition of direct labour synergies from avoided headcount positions; and
- Reduction to capital expenditures corresponding to canceled Facilities initiatives.

Capital Transition Costs

Capital-related transition costs of $86.5MM are required to provide for the integration and consolidation of IT systems and processes, in addition to Facilities renovations to accommodate for department/staff relocations, Control Room and Call Centre consolidation, and other integration initiatives.

Capital transition expenditures increased by $30.5MM over the 2019 Plan, as compared to the 2018 Plan, principally attributable to:

- Operations voice radio system transition project. Not anticipated in the original business case;
- CIS project go-live delay; and
- Facilities renovations at Derry Rd, John St, and Cityview, to accommodate for department/staff relocations, Control Room and Call Centre consolidation, and other integration project initiatives.

2.5 Workforce Planning

The following is a summary of permanent full-time equivalent ("FTE") positions of the shared consolidated organization:

Table 28: Permanent full-time equivalent positions

Employee Type	2018	2019	2020	2021	2022	2023
Executive	25.0	24.0	24.0	24.0	24.0	24.0
Management	503.4	497.3	478.3	471.0	470.0	470.0
Student	64.7	70.9	70.9	70.9	70.9	70.9
Contractor	—	3.5	2.0	2.0	2.0	2.0
Outside Union	526.2	541.2	535.2	533.4	533.0	533.0
Inside Union	385.0	365.5	311.0	310.0	310.0	310.0
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total	**1,504.3**	**1,509.4**	**1,428.4**	**1,418.3**	**1,416.9**	**1,416.9**

Note: employee complement includes employees in transitional roles

2019 Plan vs. 2018 Plan Headcount

The following table provides a comparison of permanent full-time equivalent ("FTE") positions for the shared consolidated organization between the 2019 Plan and the 2018 Plan:

Table 29: Permanent full-time equivalent positions

Employee Type	2018	2019	2020	2021	2022	2023
2019 Plan	1,439.6	1,435.0	1,355.5	1,345.4	1,344.0	1,344.0
2018 Plan	1,439.6	1,439.6	1,354.5	1,341.4	1,339.0	N/A
Total - fav (unfav)	**—**	**(4.6)**	**1.0**	**4.0**	**5.0**	**N/A**

The 2019 Plan for the LDC includes approximately three additional FTEs relative to the 2018 Plan. These additional headcount comprise: approximately eight new approved positions principally placed in the areas of Legal, Network Operations, Network Services and Information Technology; partially offset by the elimination of five permanent headcount in the areas of Business Transformation, and Customer Service. The additional headcount were justified to address current resource constraints in Network Services and Network Operations, while the additional headcount in Legal and Information Technology were to address skill gaps in the organization.

Recognition of Existing Collective Agreements

Alectra has been actively engaged in negotiations with the PWU since September 2017 to reach a collective agreement representing all unionized employees. Until a unified Collective Agreement is in place, Alectra will recognize the representative rights and collective agreements of each legacy respective bargaining unit and its members. Alectra is committed to harmonious relationships among its employees. This is critical to support: productivity; quality of customer service; employee motivation and commitment; employee attraction and retention.

Workforce Summary

The following table presents: (i) the total permanent FTE positions to support the business operations of Alectra; and (ii) the net reductions in permanent FTEs for each of the years included in the 2019 Plan.

[redacted]

* 2018 represents the budgeted headcount in the 2018 Plan

3.0 Business Risks and Opportunities

There are several material assumptions underlying the development of the 2018 Plan. Such assumptions incorporate a degree of inherent risk that could result in material differences between actual results and the 2018 Plan as presented. These risks for the LDC, Solar Partnership, and Energy Solutions entities are further elaborated within the section below.

3.1 LDC

The following tables summarize the potential impacts on 2019 pre-tax income attributable to risks and opportunities that impact revenue, operating and capital costs where it is possible to provide a range of estimates:

Table 31: Risks ($MMs)

Nature of Risk and Opportunity	Low	High
Distribution and Other Revenue		
Weather - 2019 Impact (+/- 10% consumption June-September)	(1.8)	1.8
Economy - 2019 Impact (+/- 10% demand)	(12.4)	12.4
ICM Revenue (Low - 0% recovery; High - 100% recovery)	(1.2)	1.2
Residential and Small Commercial customers - Customer Service Rules	(0.8)	(1.6)
Large Commercial customers	—	(2.2)
Operating Expenditures		
Weather Event	(2.7)	—
Operating Maintenance Programs (Non-wage) (+/- 3%)	(3.8)	3.8
Derecognition Losses on Distribution Renewal Program (+/-10%)	(0.6)	0.6
Vacancy Adjustment	(4.5)	—
Capital Expenditures		
System Access Capital (+/- 5%)	(3.9)	3.9

The following are the risks and opportunities identified for LDC:

Weather

Variability in weather, principally measured by cooling degree days throughout the summer months, could impact 2019 distribution revenue for residential customers (PowerStream Rate Zone) and GS<50 kW customer classes by as much as $1.2MM or 6.7% in 2019, based on trends experienced over the past four years. The impact on variable distribution revenue from variability in weather is assessed by comparing total consumption and variable distribution revenue for the highest and lowest number of cooling degree days experienced in the months of June to September, over the past four years. The transition to a fully fixed distribution charge for the Residential customer class in the Enersource, Brampton and Horizon Utilities rate zones in 2019 will eliminate this risk for Residential customers.

Total residential (PowerStream Rate Zone) and GS< 50kW variable distribution revenue and cooling degree days for June to September in 2016 were $19.2MM and 525 days respectively, compared to $18.0MM and 317 days in 2015. Over the past four years (2015-2018), cooling degree days, experienced in the months of June to September inclusive, have fluctuated significantly, impacting consumption for Residential customers in the PowerStream Rate Zone and GS<50 kW customers. The impact of a +/-10% change in consumption for the period June - September is +/- $1.8MM.

The LDC cannot mitigate weather-related impacts on distribution revenue in the short-term; although it may present evidence to the OEB in its periodic rate applications to mitigate the future impact of a weather-related declining revenue trend. Furthermore, the impact will be further mitigated in 2020 as the PowerStream rate zone will complete the transition to a fully fixed charge for the residential customer class.

Economy

The impact on variable distribution revenue from economic factors is assessed based on the LDC's experience during the last economic downturn. The reduction in average peak load as a result of the recession ranged from 8% to 16% across the four rate zones. The LDC has assessed that the impact of a +/- 10% change in demand for GS>50 kW and Large Use customers could impact distribution revenue by as much as 303MW/month or $12.4MM in 2019. The LDC cannot mitigate short-term impacts on distribution revenue, as a result of declining demand specifically related to the economy. Such is considered a normal business risk to the utility, and must be taken into consideration as part of the development of electricity load forecast assumptions. The LDC utilizes leading analytical tools and industry best practices to develop load forecasts. This notwithstanding, it is difficult to model load forecasts with consideration for local or broader future economic trends.

ICM Revenue

Based on the OEB’s Decision in Alectra Utilities’ 2018 EDR Application, a 50% recovery assumption for ICM revenue was included in the distribution revenue forecast. The actual percentage recovery is dependent on the OEB’s Decision in the 2019 EDR Application. The impact of 100% recovery is an increase in distribution revenue of $1.2MM; and the impact of 0% recovery is a decrease in distribution revenue of $1.2MM.

The following table provides the comparison between full recovery and 50% recovery of ICM:

Table 32: ICM Revenue Recovery ($MMs)

ICM Revenue	**2018**	**2019**	**2020**	**2021**	**2022**	**Total**	**2023**
PowerStream RZ	0.5	2.0	3.2	4.4	5.6	15.7	6.8
Enersource RZ	3.9	5.4	6.6	7.8	9.0	32.7	10.2
Horizon Utilities RZ	—	—	1.2	2.4	3.6	7.2	4.8
Brampton Hydro RZ	0.5	0.7	0.7	0.7	0.7	3.3	0.7
Total ICM - 100% Recovery	**4.9**	**8.1**	**11.7**	**15.3**	**18.9**	**58.9**	**22.5**
Total ICM - 50% Recovery (2019 Plan)	**4.9**	**6.9**	**8.7**	**10.5**	**12.3**	**43.3**	**14.1**
Difference	**—**	**1.2**	**3.0**	**4.8**	**6.6**	**15.6**	**8.4**

Residential and Small Commercial Customers - Review of Customer Service Rules ("CSR")

On September 6, 2018, the OEB issued a Report entitled, Review of Customer Service Rules for Utilities Phase One, which proposes to amend various aspects of customer service as well as to remove certain charges the utility currently collects from customers. At this time, it remains unclear what the final amendments to the Customer Service Rules will be, as well as the specific timing for the implementation of the amendments. The OEB has not indicated whether it will allow LDCs to establish a Variance Account for recovery of implementation costs or alternative relief. As mentioned above, the OEB is proposing the discontinuation of the late payment, reconnection and disconnection charges. The expected result of such a change is increased credit losses of $0.3MM per year and a reduction in late payment/ disconnection/ reconnection revenues of $1.3MM per year. The LDC estimates a total impact in 2019 of $1.6MM if the proposed changes are in effect January 1, 2019, and an impact of $0.8MM if the proposed changes are in effect July 1, 2019. At this time, the costs associated with system and business process changes, training and customer communications are unknown.

Large Commercial Customers

OEB regulation does not provide adequate protection of electricity distributors from high concentration risks such as large commercial customers. As an example, the LDC is presently not permitted to proactively secure itself against large and material commercial customers that pose a concentration risk with regard to payment defaults, other than through insurance which is generally expensive once a risk is identified. The LDC may only secure a large commercial risk following two late payments. Based on experience, large commercial customers generally pay promptly up until the point they seek financial protection from creditors under the CCAA.

OEB regulation of distributor credit policy also prevents distributors from any proactive measures to secure themselves against known or increasing credit risks. Consequently, the LDC will have an unsecured net financial exposure of 1.5 months of electricity and related charges at the time that a large commercial customer files for protection under CCAA. The credit risk associated with the write-off of the accounts receivable balance for the utility's largest customer is $2.2MM.

Weather Event

Severe weather may result in material damage to the distribution system plant that requires immediate replacement, which is not contemplated within the distribution system capital program. It may also cause material losses on retirements of distribution system plant related to severe storm or other damages, the magnitude of which is dependent upon the age of the assets. It is difficult to estimate the potential financial impact to Alectra arising from a severe weather event. Alectra may mitigate material weather-related impacts on operating costs (e.g., ice storm, tornado, etc.,) through a request for a “Z-factor” adjustment in annual adjustment filings. The materiality threshold for Z-factor adjustments is 0.5% of distribution revenue, or approximately $2.7MM.

Operating Maintenance Programs

The ability to execute the operating maintenance programs and realize expected synergy savings is a potential risk to the 2019 Plan. Changes of +/- 3% to the operating maintenance programs represent an impact to pre-tax income of +/-$3.8MM.

Derecognition Losses on Derecognition Renewal Program

Derecognition losses in the 2019 Plan have been estimated using historical information. It is difficult to estimate the range of error associated with the estimate but is could be as wide as +/- 10%; or approximately +/- $0.6MM.

Vacancy Adjustment

The 2019 Plan assumes a 3% vacancy rate within LDC, which is consistent with historical experience. There is a risk of $4.5MM to the OM&A plan if there are no vacancy savings in 2019.

Negotiation of Collective Agreement

The 2019 Plan assumes that Alectra will be able to successfully negotiate a collective agreement with the PWU and achieve outcomes in line with the merger business case. The achievement of synergies planned for Customer Service and Finance departments is dependent on a Collective Agreement which allows for: relocation of existing unionized staff; strategic outsourcing of key activities including the Call Centre, field collections, meter reading, Financial Accounting support services, and call centre back office overflow activities at peak times; and the discontinuation of some existing processes (i.e. internal management of customer bill printing). In addition, the financial outcomes outlined in the 2019 Plan will be at risk if Alectra is unable to negotiate a collective agreement with wage increases that are consistent with the assumptions underlying the 2019 Plan. A labour disruption would also put achievement of 2019 Plan results at risk.

System Access Capital

The system access capital plan can be impacted by: (i) the amount of capital contributions from customers, which is driven by the level of customer demand, as well as an economic evaluation of the related project; (ii) the timing/ achievement of the capital program could affect the amount of internal costs (most notably labour) that are ultimately absorbed into capital versus operating expenses; and iii) obligations to connect new residential and general service customers or system modifications for infrastructure development such as road widening and public transit initiatives. A change of +/- 5% represents an impact to capital expenditures of +/-$3.9MM.

Other Risks

- Material changes in regulatory assets and liabilities, which are not recognized on the balance sheet under IFRS (may have material impact to short-term cash-flow but not result in any permanent benefit or impairment to earnings or cash flow).
- Changes in regulation generally that may have financial implication to regulated electricity distributors and their customers.
- Ability to execute the expected synergy savings incorporated in the 2019 Plan including reductions in operating expenditures, increased capacity, and future cost avoidance.
- Unforeseen reactive capital or maintenance work that has not been included in the 2019 Plan might impact the targeted results.
- Unanticipated delays and/or cost increases for major transition projects

[redacted]

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[redacted]

4.0 Financial Plan

Financial Plan Highlights

Exhibits A-H - Financial Statements provide the Statement of Financial Position, Statement of Comprehensive Income and Retained Earnings, and Statement of Cash Flows on a consolidated, shared consolidated, and entity-level basis.

The following table provides a net income comparison between the 2019 Plan to the 2018 Plan.

Table 33: Net Income reconciliation to the 2018 Plan ($MMs)

MIFRS Net Income		2018	2019	2020	2021	2022	Total	2023
[redacted]								
LDC	2019 Plan	122.1	114.4	128.2	120.1	125.8	610.6	128.5
	2018 Plan	108.9	126.3	135.7	137.5	141.6	650.0	NA
	Variance	**13.2**	**(11.9)**	**(7.5)**	**(17.4)**	**(15.8)**	**(39.4)**	**NA**
[redacted]								
LDC Merger impact *	2019 Plan (pre-merger)	122.1	112.8	123.8	114.9	119.0	592.6	121.1
	GHESI	—	2.6	5.8	6.6	8.2	23.2	8.9
	GRE&T	—	(1.0)	(1.4)	(1.4)	(1.4)	(5.2)	(1.5)
	2019 Plan (post-merger)	122.1	114.4	128.2	120.1	125.8	610.6	128.5
	2018 Plan	108.9	126.3	135.7	137.5	141.6	650.0	NA
	Variance	**13.2**	**(11.9)**	**(7.5)**	**(17.4)**	**(15.8)**	**(39.4)**	**NA**

Please refer to Table 16 in Section 2.3 for the impact of GHESI and GRE&T on net income and dividends on Shared Consolidated entity

A summary of all the underlying drivers of the variances are described in detail below.

Dividends

The following table provides a dividend comparison between the 2019 Plan to the 2018 Plan.

Table 34: Dividend reconciliation to the 2018 Plan ($MMs)

Dividends at Policy		2018	2019	2020	2021	2022	Total	2023
[redacted]								
LDC	2019 Plan	67.2	74.7	76.9	72.0	75.5	366.3	77.1
	2018 Plan	70.5	75.8	81.4	82.5	85.0	395.2	NA
	Variance	**(3.3)**	**(1.1)**	**(4.5)**	**(10.5)**	**(9.5)**	**(28.9)**	**NA**
[redacted]								

Variances to the prior plan are directly driven by the differences in net income. As such, 2018-2022 results in the 2019 Plan are unfavourable to dividend expectations set in the 2018 Plan.

[redacted]

[redacted]

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Dividend Policy

Dividends are determined at the discretion of the Board of Directors.

Shareholders of voting shares are eligible to receive non-cumulative dividends with a target of 60% of the Corporation's consolidated net income as reported under MIFRS for the electricity distribution business and IFRS for the unregulated business, excluding financial results relating to the RFSP. Payments of the dividends are made quarterly in arrears.

The Dividend Policy provides for quarterly dividends as follows:

- Up to 20% of the Corporation's Voting Common Dividend for the Voting Common Shares;
- Payments on March 31st, June 30th, September 30th and December 31st in arrears from the prior quarter but within 10 business days following the date of declaration;
- The March 31st dividend will include the quarterly dividend in respect of the fourth quarter of the preceding year and any further adjustment to bring the total annual dividend for the preceding year up to, in each case, the full Voting Common Dividend as determined by the Board.

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Table 45: Depreciation expenses - 2019 Plan Variances to 2018 Plan for the Local Distribution Company by category ($MMs)

	2019	**2020**	**2021**	**2022**	**Total**
Depreciation expense (2018 Plan)	**127.2**	**132.1**	**138.7**	**144.6**	**542.6**
Distribution assets	6.3	7.6	9.7	10.3	33.9
Capital contributions	0.1	1.1	1.3	1.3	3.8
Deferred revenue	(2.2)	(1.9)	(1.5)	(1.0)	(6.6)
Net Distribution Assets	**4.2**	**6.8**	**9.5**	**10.6**	**31.1**
Computer software	(0.4)	2.2	2.9	3.5	— 8.2
Stores equipment	—	—	0.1	0.3	0.4
Computer hardware	(0.1)	0.1	0.1	—	0.1
Rolling stock/ fleet	(0.7)	(0.2)	—	0.3	(0.6)
Tools, shop, and garage equipment	(0.2)	(0.1)	(0.1)	(0.1)	(0.5)
Buildings, office furniture and equipment	—	—	(0.3)	(0.6)	(0.9)
Other assets	—	0.4	1.0	1.0	2.4
Total depreciation (before ICM adjustments)	**2.8**	**9.2**	**13.2**	**15.0**	**40.2**
ICM adjustments	(0.4)	(1.3)	(2.5)	(3.8)	(8.0)
Impact of lease standard changes	0.8	0.8	0.8	0.4	2.8
Total variance	**3.2**	**8.7**	**11.5**	**11.6**	**35.0**
Depreciation expense (2019 Plan)	**130.4**	**140.8**	**150.2**	**156.2**	**577.6**

Depreciation costs have increased relative to the prior year plan primarily attributable to: i) a shift in the capital plan towards faster amortizing computer software assets; ii) changes in annual depreciation from in-service assets as a result of refinements to depreciation calculations in the course of harmonizing processes; iii) higher forecast in-service distribution assets; and iv) increased depreciation due to the implementation of IFRS 16-Leases.

[redacted]

[redacted]

[redacted]

[redacted]

5.0 Capital Plan

5.1 LDC Capital

The LDC core capital investment plan for 2019-23 was developed using asset management practices that optimize the performance and lifecycle costs of all assets in a safe, reliable, and sustainable manner. The plan includes prudent capital investments aligned with objectives to enhance distribution system operations and improve the customer service experience. The capital investment plan incorporates customer preferences and considers legacy Distribution System Plans. Business cases for projects and programs were developed, reviewed, and evaluated against corporate objectives and risks. Capital investments identified from business cases were assembled based on the following investment categories: (i) SA; (ii) SR; (iii) SS; and (iv) GP. The investment categories are further elaborated below. Capital projects and programs are selected, paced, and prioritized based on considerations for benefits, risk mitigation, customer input and regulatory compliance obligations. The 2019-2023 capital investment plan was developed with alignment to transition and synergy related initiatives for certain general plant investments common across all service areas. Please refer to section 2.4 for details regarding the transition capital expenditures and capital synergies.

The capital investment plan strives to maintain assets in a manner that delivers sustainable value; mitigates risks; complies with regulations; codes and standards; and meets corporate performance targets.

The 2019-2023 capital investment portfolio was developed incorporating customer preferences acquired through customer engagement process initiatives. In 2018, customer surveys were undertaken to better understand customer priorities. The surveys identified that customers are generally satisfied with the level of service they receive. Customers communicated their reluctance to fund emerging grid technology initiatives in rates, while reiterating their willingness to pay for reliability and maintenance activities.

During the development of the capital investment plan, customer preferences and priorities were integrated into a selection and prioritization process by addressing: reliability issues; pacing investment in system expansion; limited grid modernization investments in Distributed Energy Resources; MicroGrid; and electric vehicle charging system controls to pilot studies. In 2019, LDC will complete a customer engagement to attain input, preferences, and priorities on distribution system plans.

Capital projects and programs incorporated into the 2019 Plan will evolve distribution system flexibility to meet the current and future customer needs. The capital investment plan focuses on enhancements, operational effectiveness and system performance to align with the long term plans, which provide a coordinated approach to deliver effective system renewal and paced system modernization investments. Investments in new distribution system monitoringtechnologies will enhance asset oversight, increase system utilization, and improve reliability and performance. The plan supports monitoring, analytics, and business intelligence to deliver operational excellence and continuous improvement.

The capital investment plan further supports the development of diverse competencies to enable adaption of advanced analytics systems and fact based decision making. The operational benefit of advanced analytics systems include improvements of monitoring and trending capital project labour and material costs within the CopperLeaf C55 Investment Portfolio System. The CopperLeaf C55 system was implemented to enable the evaluation of all capital investments using common criteria incorporating risk mitigation and value benefits such as financial, resource, time and risk constraints.

Capital Investment Planning Process

The 2019-2023 capital investment plan was developed through the identification of business needs and requirements, based on external and internal drivers, and investment considerations. External drivers include regulatory; municipal; and customer driven investments. Internal drivers include asset condition assessments; roadmaps; and system capacity studies. The investment considerations include growth projections; safety; reliability; and emerging technology opportunities.

Capital investment requirements are based on system capacity constraints, equipment condition, operational needs, and opportunities for efficiency improvements. Capital project and program solutions were developed based on the identified needs and customer preferences. Sustainment and renewal expenditures were based on asset condition assessments, system utilization studies, and prioritized expenditures from long term plans.

In 2018, the CopperLeaf C55 Investment Portfolio System was implemented. This system provides a repository of all capital expenditure business cases with the capability to leverage common criteria for evaluating all capital expenditures for the LDC. Over 1,000 business cases were developed evaluating benefits and risks in relation to optimizing operations, safety, lifecycle management, and processes such as: asset renewal; leveraging emerging technologies to enhance system reliability; and enabling grid integration to advance system flexibility and alternative services for customers. This information informs the evaluation and prioritization of capital investments. For example, a capital investment driven mostly by a reliability benefit was compared against a capital investment driven by financial and reputation risk through the quantification of each benefit and risk into a present time value. The five-year capital expenditure portfolio was optimized to balance risk and benefits while considering customer preferences and priorities.

2019-2023 Core Capital Expenditure Plan

The five year capital expenditure plan is organized within four categories corresponding to the OEB's Renewed Framework for Electricity Distributors. Considering all investment categories and rate zones, the total core capital expenditure program aggregates $1.4B over the 2019-2023 period as outlined in Table 50 below. Management isseeking approval for 2019 and 2020 capital expenditures of $253.0MM and $280.0MM respectively. The benefits of a two year capital expenditure plan approval include: enhancement in project planning and scheduling; increased flexibility in resource assignment; and improved supply chain management with respect to projects with a long lead time for supply fulfillment; as well as mitigation of risks of delays related to permitting and municipal consent. The values provided in the table below are not inclusive of synergies or transitional costs. Please refer to section 2.4 for an analysis of merger synergies and transition costs, including capital-related items, incorporated into this Financial Plan.

Table 50 - LDC's 2019-2023 Core Capital Expenditure Costs ($MMs)

($MM)	2018 Forecast	2019	2020	2021	2022	2023	Total
System Access	157.8	195.1	165.3	144.1	139.8	126.0	**928.1**
System Service	23.7	25.5	37.3	37.2	34.8	49.3	**207.8**
System Renewal	112.9	125.1	134.6	137.1	147.9	147.4	**805.0**
Gross Distribution System Capital	**294.4**	**345.7**	**337.2**	**318.4**	**322.5**	**322.7**	**1,940.9**
Capital Contributions	(72.4)	(116.6)	(95.0)	(76.1)	(77.8)	(60.0)	**(497.9)**
Total Net Distribution System Capital	**222.0**	**229.1**	**242.2**	**242.3**	**244.7**	**262.7**	**1,443.0**
Net General Plant	17.7	23.9	37.8	32.3	38.8	29.5	**180.0**
TOTAL CORE CAPITAL (NET)	**239.7**	**253.0**	**280.0**	**274.6**	**283.5**	**292.2**	**1,623.0**
ICM Recovery Assumption	—	(15.9)	(29.0)	(26.3)	(30.7)	(35.2)	**(137.1)**
Transition Capital	45.1	34.8	3.6	3.0	—	—	**86.5**
Total capital expenditures	**284.8**	**271.9**	**254.6**	**251.3**	**252.8**	**257.0**	**1,572.4**

System Access (SA)

SA investments represent mandatory upgrades to the distribution system that provide customers access to electrical services. Investments in the SA category include new customer connections as well as system modifications for infrastructure development such as road widening and public transit initiatives. Drivers for such investments include customer service requests for connection, new development applications, and road authority requests. Obligations for system access investments include the DSC, corporate Conditions of Service, and the Public Service Works on Highway Act. SA projects are considered mandatory expenditures in the 2019 Plan.

The five year distribution system plan for SA investments is largely driven by the requirement to connect new residential and general service customers. The planned gross/ net capital expenditures for SA are $332.0MM/ $148.6MM, respectively, over the next five years to connect new customers. Significant investments in SA over the next five years are required to support road widening and transit infrastructure projects, including: the York Region Rapid Transit; Hurontario Light Rail Transit; and the Hamilton Light Rail Transit projects. The five-year planned investment in road authority work is $330.9MM Gross ($103.6MM net of capital contributions). The capital plan in metering includes$16.0MM necessary to replace specific residential smart meters that currently have unreliable wireless communication cards and obsolete encryption capability. In 2019, the customer emerging expenditures will invest $4.8MM in infrastructure to support the capacity requirements for the Juravinski Hospital.

The following table outlines the core capital expenditures in SA, excluding any capital transition and/ or synergies.

Table 51 - 2019-2023 Core Capital Expenditure: System Access ($MMs)

SYSTEM ACCESS ($MM)	2018 Forecast	2019	2020	2021	2022	2023	Total
New Connections	59.3	59.6	63.9	67.8	70.7	70.0	**391.3**
Road Authority / Transit	70.7	106.2	78.8	52.6	54.2	39.1	**401.6**
Metering	8.6	13.2	15.1	17.9	8.8	10.5	**74.1**
Emerging Customer Work	4.7	12.8	4.0	4.3	4.6	4.8	**35.2**
Other System Access	14.5	3.3	3.5	1.5	1.5	1.6	**25.9**
System Access Total (GROSS)	**157.8**	**195.1**	**165.3**	**144.1**	**139.8**	**126.0**	**928.1**
Capital Contributions	(72.4)	(116.6)	(95.0)	(76.1)	(77.8)	(60.0)	**(497.9)**
System Access Total (NET)	**85.4**	**78.5**	**70.3**	**68.0**	**62.0**	**66.0**	**430.2**

System Renewal (SR)

SR investments support the replacement or the refurbishment of distribution system assets for the purpose of renewing and/ or extending the original asset service life. Investments in SR enable the distribution system to maintain reliable electrical service to customers and include investments to replace and rebuild distribution system assets such as poles, conductors, switchgear, cables, transformers and insulators. Asset condition assessments are undertaken to determine the health condition of assets based on current asset status, utilization as well as inspection, testing and maintenance records. Asset condition assessments inform the priority and timing needs of replacement or refurbishment of assets.

The five year expenditure plan for SR is primarily driven by the need to replace aging and deteriorated underground distribution system assets as well as voltage conversion for outdated distribution systems. Over the five year period, planned expenditures to replace and rehabilitate deteriorated underground cables will cost $305.0MM. This investment is expected to reduce the number of cable failures and volume of aging infrastructure identified through asset condition tests. The five year plan includes investments to mitigate environmental risks with respect to transformer oil leakage.

The following table outlines the core capital expenditures in SR, excluding any transition expenditures.

Table 52 - 2019-2023 Net Capital Expenditure: System Renewal ($MMs)

SYSTEM RENEWAL ($MM)	2018 Forecast	2019	2020	2021	2022	2023	Total
Underground line replacement	39.9	37.7	53.3	66.1	72.2	75.7	344.9
Overhead line replacement	33.5	39.9	30.5	31.2	35.8	27.2	198.1
Substation renewal	5.1	4.5	11.8	4.0	2.0	2.5	29.9
Reactive	17.1	18.1	19.8	20.4	21.4	22.0	118.8
Transformer replacements	10.1	12.0	5.2	5.9	6.6	7.0	46.8
Storm hardening & rear lot conversion	1.0	6.7	7.2	2.9	3.1	6.0	26.9
Other system renewal	6.2	6.2	6.8	6.6	6.8	7.0	39.6
System renewal total (net)	**112.9**	**125.1**	**134.6**	**137.1**	**147.9**	**147.4**	**805.0**
ICM recovery assumption	—	(11.6)	(19.7)	(17.8)	(20.7)	(23.4)	(93.2)
Revised system renewal total (net)	**112.9**	**113.5**	**114.9**	**119.3**	**127.2**	**124.0**	**711.8**

System Service (SS)

SS investments are modifications to the distribution system to ensure the distribution system continues to meet operational objectives while addressing anticipated future service capacity and reliability. SS investments enhance the distribution systems grid flexibility to meet anticipated future customer electricity service requirements, including distributed generation and storage. Investments in SS include modernization of protection and control systems to ensure the safe and reliable operation of the system; system station investments necessary to maintain the safe and efficient delivery of electrical service to customers; and investments in system automation and remote operating capabilities to permit expedient restoration of service in times of unforeseen outages. Drivers for system service requirements include increases in customer demand; and requirements to continue to provide safe, reliable and quality electrical supply to customers.

The five year expenditure plan for SS is primarily driven to expand system capacity, facilitating growth, and expansion. Over the five year period, Alectra Utilities plans to invest $97.2MM in system expansion to support growth of residential, commercial, and industrial customers. Specifically, capacity investment are increased from 2020 to 2023 to include: feeder expansion work in Markham ($4.9MMM); feeder expansion required to provide capacity to the Hamilton LRT ($4.8MM); and feeder integration in Vaughan ($4.0MM).

Additionally, $4.0MM is allocated over the planning period to replace deteriorated and undersized overhead conductors in Hamilton. This investment is essential to mitigate the risk of frequent failures, and energized downed lines.

Additional investments will address municipal station upgrades, and system automation.

The following table outlines the core capital expenditures in SS, excluding any capital transition and/ or synergies.

Table 53 - 2019-2023 Capital Expenditure: System Service ($MMs)

SYSTEM SERVICE ($MM)	2018 Forecast	2019	2020	2021	2022	2023	Total
Capacity	5.8	7.0	20.7	22.9	20.3	26.3	**103.0**
Station upgrades (Capacity)	6.8	3.2	—	1.6	2.2	6.2	**20.0**
Reliability	3.3	9.1	8.0	6.6	6.1	10.7	**43.8**
Safety	—	2.7	4.9	1.8	1.9	1.9	**13.2**
Security	1.7	0.4	0.4	0.1	0.1	0.1	**2.8**
Power quality	—	—	0.1	0.9	0.6	—	**1.6**
System efficiency	—	0.3	0.6	0.6	0.5	0.5	**2.5**
Automation, SCADA	4.9	0.5	0.4	0.5	0.5	0.5	**7.3**
Subtransmission	0.9	—	—	—	—	0.5	**1.4**
Other system service	0.3	2.3	2.2	2.2	2.6	2.6	**12.2**
System Service Total (net)	**23.7**	**25.5**	**37.3**	**37.2**	**34.8**	**49.3**	**207.8**
ICM recovery assumption	—	(2.4)	(5.5)	(4.8)	(4.9)	(7.8)	**(25.4)**
Revised system service total (net)	**23.7**	**23.1**	**31.8**	**32.4**	**29.9**	**41.5**	**182.4**

General Plant (GP)

GP investments support the day to day business and operations activities for the utility and involve assets that are not a direct part of the distribution system. General plant assets principally include: computer systems and software such as billing, enterprise resource planning, and geographical information systems; land, buildings and furniture; and transportation equipment and tools necessary to perform operational and administrative business activities.

The five year expenditure plan for GP is primarily driven by the need to enhance information systems to improve efficiency, advance innovative technology into practice, and renew aged and obsolete computing assets. Over the five year period, the GP plan provides for:

- $73.1 MM in computer hardware and software solutions, including $11.3MM in 2020 for a CIS system platform upgrade to supported version of the Customer Care and Billing System; and
- $42.9MM in updated transportation equipment to support the ability of Alectra Utility crews to respond to the needs of the distribution system in an efficient and safe manner.

The following table outlines the core capital expenditures in GP, excluding any capital transition and/ or synergies.

Table 54 - 2019-2023 Capital Expenditure: General Plant ($MMs)

GENERAL PLANT	2018 Forecast	2019	2020	2021	2022	2023	Total
Computer hardware and software	6.0	10.2	14.5	15.2	22.8	10.4	**79.1**
Buildings, furniture and fixtures	0.7	3.4	3.9	4.3	4.3	4.3	**20.9**
Transportation equipment	6.6	6.7	8.3	8.9	9.3	9.7	**49.5**
Tools, shop and garage equipment	1.2	1.6	1.2	1.2	1.2	1.2	**7.6**
Other general plant	3.2	2.0	9.9	2.7	1.2	3.9	**22.9**
General plant total (net)	**17.7**	**23.9**	**37.8**	**32.3**	**38.8**	**29.5**	**180.0**
ICM recovery assumption	—	(2.0)	(3.9)	(3.7)	(5.1)	(3.9)	**(18.6)**
Revised general plant total (net)	**17.7**	**21.9**	**33.9**	**28.6**	**33.7**	**25.6**	**161.4**

Comparison to Previous Financial Plan

The table below provides a breakdown of Net capital expenditures, excluding synergy and transition costs for the five year plan relative to the 2018 Plan:

Table 55 - 2018-2023 Net Capital Expenditure Costs compared to 2018 Plan ($MMs)

	2018	2019	2020	2021	2022	Total	2023
2019 Plan	239.7	253.0	280.0	274.6	283.5	**1,330.8**	292.2
ICM recovery assumption	—	(15.9)	(29.0)	(26.3)	(30.7)	(101.9)	(35.2)
Revised 2019 Plan	**239.7**	**237.1**	**251.0**	**248.3**	**252.8**	**1,228.9**	**257.0**
2018 Plan	266.8	257.3	270.6	269.9	272.9	**1,337.5**	N/A
Difference - fav (unfav)	**27.1**	**20.2**	**19.6**	**21.6**	**20.1**	**108.6**	**N/A**

The revised 2019 capital investment plan is lower compared to the 2018 capital investment plan largely due to the reduction related to the recovery assumption in the 2019 plan as a result of previous OEB decisions on incremental capital funding.

Summary of the Largest 2019 and 2020 Capital Projects

Overhead Line Rebuilds (SR) - 2019: $39.9MM; 2020: $30.5MM

Overhead distribution system expenditures are comprised of poles, towers, wires, switches and insulators; all forming part of a system designed to transmit electricity across the distribution system. Support structures include wood, concrete, steel and composite all having different life cycles. Data obtained from inspection, testing and maintenance programs inform asset condition assessments to enable health indexing of these components. Health indexing is used in conjunction with: evaluating operational risks; performing system planning; assessing criticality and impact of failure; reliability performance; meeting new capacity or regulatory requirements; as well as determining environmental and other stakeholder impacts to identify overhead line replacement. Overhead line replacements are identified and selected to provide the lowest costs and longest life-cycles while meeting prescribed codes, standards, and distribution system performance targets.

Underground Line Replacement (SR) - 2019: $37.7MM; 2020: $53.3MM

Underground cable systems enable the delivery of power flow from transformer stations and municipal substations across various right-of-ways into the distribution grid and ultimately to customers. Underground cable systems include various sizes and vintages of cable types, some dating back to the 1950s, and, as with most assets, cables have a limited service life. Many in-service cables have exceeded their useful life, and others have reached the end of their typical useful life. Underground cable failures are a leading cause of equipment failure in the distribution system and present a significant source of operational risk. In order to address this issue, ongoing cable replacements are assessed based on a significant amount of qualitative and quantitative analysis. On an annual basis, the worst performing areas of the underground cable system are identified and ranked according to operational risk; impact to customers; cost; labour availability; and other constraints. Remediation plans are developed to address the substandard system performance and incorporated in the subsequent capital investment plan. The capital investment plan includes emerging project investments to address urgent system renewal that requires imminent replacement.

New Customer Connections (SA) -2019: $59.6MM (Gross); 2020: $63.9MM (Gross)

New customer connections are an ongoing category of capital expenditures comprised of non-discretionary projects initiated by developers, where investment is required to enable customers to connect to the distribution system. Connection requests generally originate with respect to: new industrial developments; high, medium and low density residential subdivisions; and commercial developments. These investments are not discretionary, somewhat reactionary, and cannot be deferred. Expenditures corresponding to new subdivision projects are forecasted based on a variety of factors including: historical levels of activity and investment; housing and population growth studies; known developments in the planning stages using zoning information and permit applications; municipal plans; and review of economic factors. Alectra is mandated to ensure that all electrical connections to its system meet design requirements in accordance with the Distribution System Code and Conditions of Service.

Road Authority Requests (SA) - 2019: $43.4MM (Gross); 2020: $28.3MM (Gross)

The majority of the distribution plant is located within the public road allowance. The provincial Ministry of Transportation, regional and municipal road authorities may, at their discretion, initiate projects to construct, re-construct, change, alter, improve or relocate roads as necessary based on their planning needs. This category of capital is required for relocating existing overhead and underground plant that is in conflict with the new road layout to facilitate the needs of road authorities. Other related projects that may be associated with road widening projects include, but are not limited to, the installation of sidewalks, water main supply, and sanitary and storm sewer infrastructure. The *Public Service Workson Highways Act* and associated regulations dictate the recovery of costs related to road reconstruction work and provide for contributed capital for 50% of labour and labour saving devices. Staff work closely with the various road authorities to develop short term and long-term planning forecasts of roadway improvement projects. However, the initiation and timing for the execution of these projects is outside of the control of the LDC and, consequently, the timing and value of this required investment may be subject to change.

Transit Projects (SA) - 2019: $62.8MM (Gross); 2020: $50.5MM (Gross)

Transit initiatives are implemented by either a provincial or regional corporation. The scope of each project includes participating with these corporations during the pre-market, in-market, and in-development periods of the projects to ensure that any obstructing distribution infrastructure is relocated in a timely manner to allow for rapid transit installations. Current transit projects include: HuLRT, HaLRT, and the RER.

The RER project has a scope of relocating approximately 89 overhead obstructions along the Barrie, Stouffville, Kitchener and Lakeshore West GO Rail Corridors at a Gross cost of $41.4MM, with a requested completion date of 2021. All of such costs are recoverable from Metrolinx.

The HaLRT project scope involves the relocation of distribution infrastructure along the 14 kilometer LRT route in Hamilton at a recoverable cost of $12.5MM within the 2019 Plan timeframe.

The HuLRT project scope involved the relocation of Alectra Infrastructure along the 20.9 kilometer LRT route in Mississauga and Brampton at a recoverable cost of $9.8MM within the 2019 Plan timeframe.

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6.0 Financing Plan

6.1 Objectives

The Financing Plan incorporates the following objectives:

- Cost effective liquidity to support sustainability and growth objectives;
- Sustain a long-term A-range rating, particularly with respect to the distribution business; and
- Manage liquidity and interest rate risks.

Based on its existing structure, this requires managing within the following financial parameters:

- Debt to Capital (excluding non-cash appraisal / valuation adjustments) around 60-65%;

* AFFO: Debt sustainably at or above 13%; and
* Non-regulated assets and cash flows below 10% of consolidated statistics.

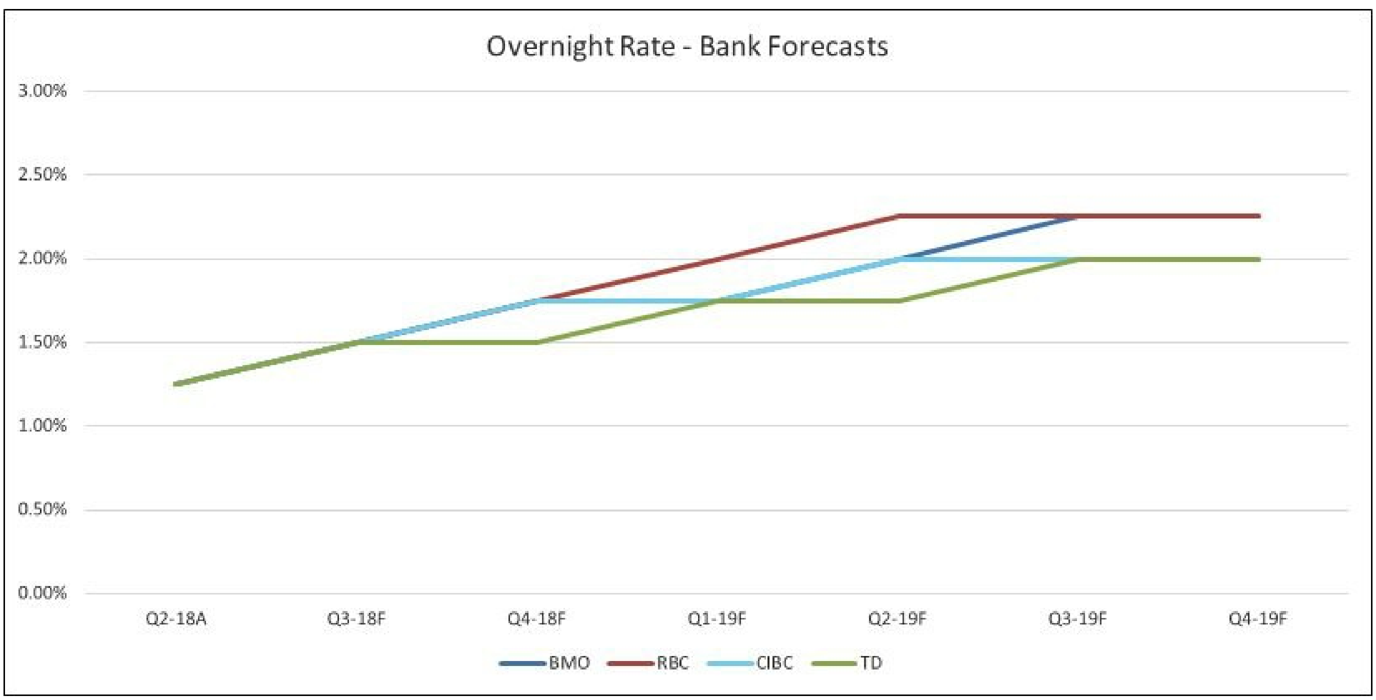
In the medium-term, Alectra will investigate opportunities to extend its balance sheet in support of regulated and non-regulated growth through:

* Structured approaches to access equity financing;
* Manage transfer and departure tax barriers;
* Manage overall cost of capital considering regulated and non-regulated business growth; and
* Ratings/cost of capital segregation between regulated/ non-regulated businesses.

6.2 Interest Rate Assumptions

Short-term Interest Rates

The Bank of Canada raised the overnight lending rate by 25 bps in July 2018. The Bank has raised its key rate four times since June 2017 in response to improved economic growth. The Canadian chartered banks forecasts of overnight lending are provided in the chart below:



These increases have had a negative impact on short-term lending rates. The prime rate was 3.20% at the beginning of 2018. The prime rate is budgeted to be 3.95% by the end of 2018, based on another forecasted increase of 25 bps in Q4 2018, and 4.45% by the end of 2019, based on two forecasted 25 bps increases in 2019. These increases inshort-term interest rates will have a negative impact on short-term interest costs. All increases in short-term lending rates have been incorporated into the 2019 Plan.

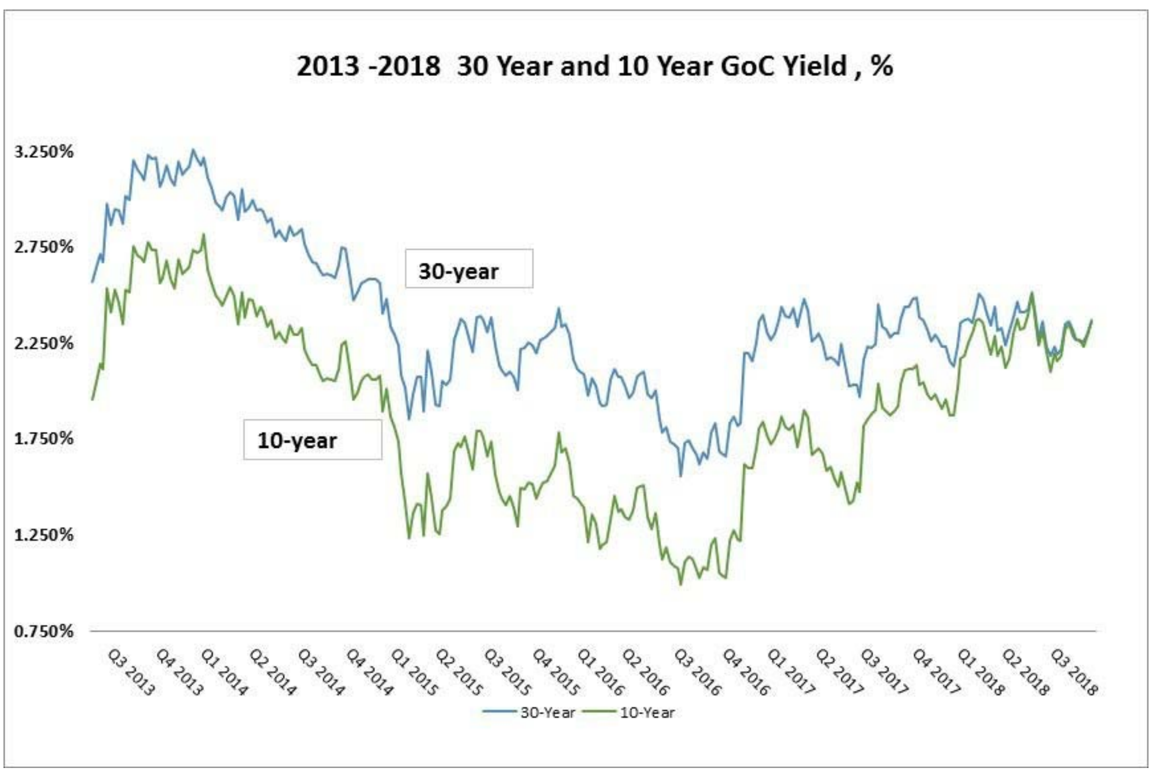
In 2018, short-term cash requirements were financed through prime loans, BA, and CP (beginning in Q4); at an average rate of 2.40% to the end of Q3. The forecasted average prime rate for 2019 is 4.30%, and 4.45% in future years. The forecasted average BA rate for 2019 is 3.00% and 3.15% in future years, and the forecasted average CP rate for 2019 is 2.70% and 2.85% in future years. Approximately $0.3MM of savings from the CP program are expected to be realized in 2019 and future years.

Table 59: The Financing Plan assumptions on short term borrowing costs are summarized in the table below:

	2019	2020 and after
Prime rate	4.30%	4.45%
BA rate	3.00%	3.15%
Commercial Paper	2.70%	2.85%

Long-term Interest Rates

The long-term rates are determined based on the forward rates for 10 and 30 year bonds for 2019, 2021 and 2023, as provided by chartered Canadian banks. Historical trends of 30-year and 10-year GoC bonds are illustrated in the chart below:



Under the current assumptions, the term premiums are not expected to significantly increase in the forecasted period. Assuming that Alectra's credit spreads to GoC bonds are stable, as illustrated in the chart below, the long-term rates are expected to stay relatively low in the forecast period.

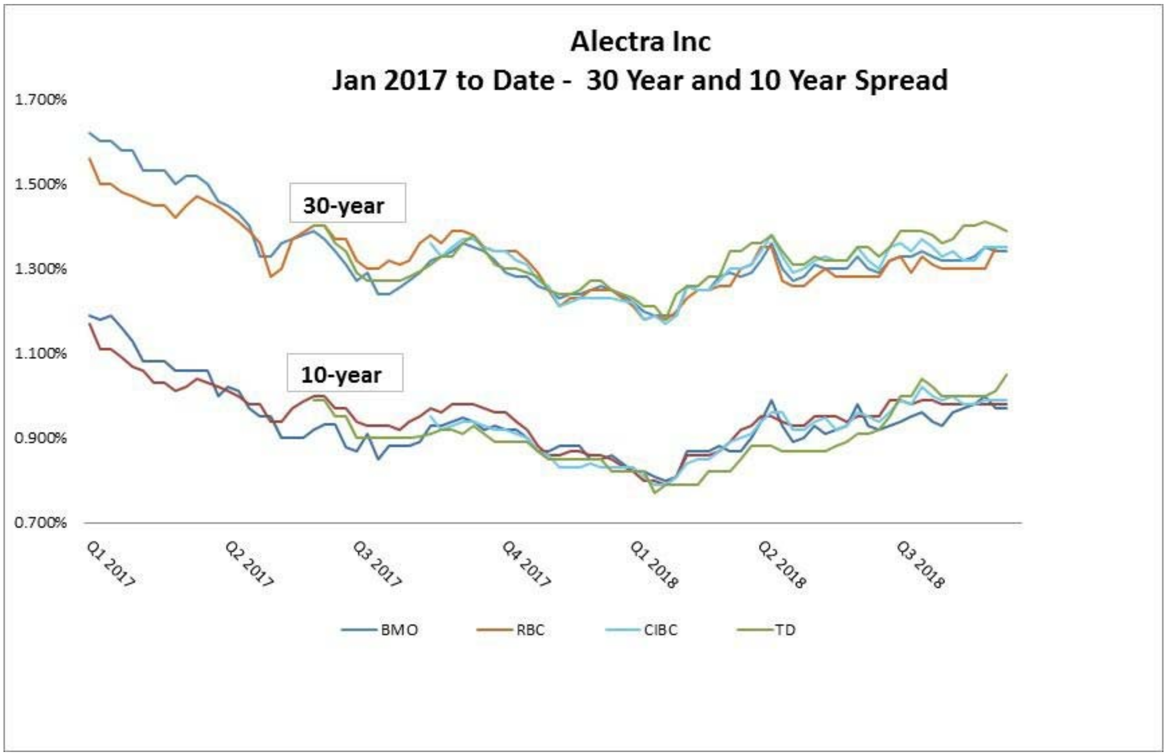


Table 60: The Financing Plan assumptions on new issuances are summarized in the table below:

	2019	2021	2023
30-year forward rate	3.75%	3.80%	3.85%

Long-term interest rate increases are forecast to lag short-term rate changes. The 30-year forward rates, as published by CIBC on August 9, 2018, were used to forecast: the rate of 3.75% for the issuance planned for 2019; the budgeted forward rate of 3.80% for the planned issuance in 2021; and the budgeted forward rate of 3.85% for the planned issuance in 2023. At the time of issuance, Alectra may consider mid-range, 10-year debt, or a combination of 10-year and 30-year debt. The 10-year forward rates as published by CIBC on August 9, 2018 were: 3.45% in 2019; 3.55% in 2021; and 3.65% in 2023.

Alectra will consider an appropriate bond term as it approaches planned issuances dates.

6.3 Sources of Liquidity

Short-Term Financing

Alectra has a committed $500MM unsecured revolving credit facility with two large banks to support working capital and general corporate requirements (“Revolver”).

In 2017, Alectra secured an additional $100MM from a Schedule A bank in the form of overdraft protection.

In 2018, Alectra established a $300MM CP program. Credit facility support for the CP program is carved out of the existing $500MM demand facility leaving $200MM for BA and Letter of Credit financing. CP is short-term debt issued in the form of an unsecured promissory bearer note. CP is not backed by a bank like a BA but may be issued by companies with strong credit ratings. It is an efficient and common method of obtaining short-term financing.

Long-Term Financing

Alectra assumed the existing trust indentures of each predecessor utility and may issue long-term senior unsecured debentures under those indentures. In 2017, Alectra established a new Trust Indenture and issued debentures of $675MM thereunder.

6.4 Financing Plan Assumptions

The Financing Plan assumes:

- issuance of $200MM in senior unsecured debentures under the Alectra Trust Indenture in the first quarter of 2019 for financing incremental balance sheet growth;
- issuance of $250MM in senior unsecured debentures under the Alectra Trust Indenture in 2021 for financing incremental balance sheet growth and debt maturities;
- issuance of $250MM in senior unsecured debentures under the Alectra Trust Indenture in 2023 for financing incremental balance sheet growth and debt maturities; and
- use of the Revolver, Commercial Paper, and Alectra Trust Indenture to finance balance sheet growth and future debt maturities.

6.5 Refinancing

The following table identifies the existing and projected fixed-term debt obligations for Alectra.

Table 61: Existing and projected new fixed-term debt obligations ($MMs)

Source	Coupon Rate	Term (years)	2019	2020	2021	2022	2023
Debentures Series A due July 2020	4.770%	10	40.0	—	—	—	—
Debentures Series A due April 2021	4.521%	10	110.0	110.0	—	—	—
Debentures Series A due July 2022	3.033%	10	150.0	150.0	150.0	—	—
Debentures Series B due November 2024	3.239%	10	150.0	150.0	150.0	150.0	150.0
Debentures Series A due May 2027	2.488%	10	675.0	675.0	675.0	675.0	675.0
Debentures Series B due April 2041	5.297%	30	210.0	210.0	210.0	210.0	210.0
Debentures Series A due July 2042	3.958%	30	200.0	200.0	200.0	200.0	200.0
Shareholder Note Payable due May 2024	4.410%	16	20.0	20.0	20.0	20.0	20.0
Shareholder Note Payable due May 2024	4.410%	20	78.3	78.3	78.3	78.3	78.3
Shareholder Note Payable due May 2024	4.410%	20	67.9	67.9	67.9	67.9	67.9
New in 2019 Debentures Series B due Jan 2049	3.750%	30	200.0	200.0	200.0	200.0	200.0
New in 2021 Debentures Series C due Mar 2051	3.800%	30	—	—	250.0	250.0	250.0
New in 2023 Debentures Series D due Jan 2053	3.850%	30	—	—	—	—	250.0
Total			**1,901.2**	**1,861.2**	**2,001.2**	**1,851.2**	**2,101.2**

At the time of maturity, renewals of the obligations will be treated as new issuances under Alectra.

The amount and timing of any new debt issuance will be determined with due regard for: the minimum amount that can be issued economically; avoiding excessive cash balances; and ensuring that draws on the short-term credit facility remain well within tolerable limits such that adequate short-term liquidity is preserved for working capital and contingencies. The actual timing, amount and term of a new debt issuance will also be influenced by several factors, including: current liquidity requirements; borrowing capacity; market conditions; and interest rate environment. Based on indicative pricing, the assumed yield for issuances in 2019 is 3.75%, for issuances in 2021 is 3.80% and for issuances in 2023 is 3.85%.

6.6 Requirements for Financial Capital

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[redacted]

[redacted]

Exhibit B1 - Alectra Shared Consolidated - Statement of Comprehensive Income - MIFRS ($000s)

[redacted]

Exhibit B2 - Alectra Shared Consolidated - Statement of Financial Position - MIFRS ($000s)

2018	2019	2020	2021	2022	2023

[redacted]

Exhibit B3 - Alectra Shared Consolidated - Statement of Cash Flows - MIFRS ($000s)

	2018	2019	2020	2021	2022	2023

[redacted]

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Exhibit B4 - Alectra Shared Consolidated Financial Results and Selected Metrics ($000s)

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Exhibit C1 - Electricity Distribution Operations - Statement of Comprehensive Income - MIFRS ($000s)

	2018	2019	2020	2021	2022	2023
Revenue:						
Distribution revenue	528,613	539,316	550,939	568,508	586,616	605,061
Electricity sales	2,758,497	2,884,141	2,944,407	2,985,864	3,035,176	3,086,507
Cost of power	(2,758,497)	(2,884,141)	(2,944,407)	(2,985,864)	(3,035,176)	(3,086,507)
Other income	46,535	32,534	26,503	27,068	27,218	27,104
Total net revenue	**575,148**	**571,850**	**577,442**	**595,576**	**613,834**	**632,165**
Expenses:						
Operating expenses	243,416	247,756	224,413	228,280	232,045	238,670
Depreciation	122,722	130,385	140,808	150,155	156,202	159,553
Total expenses	**366,138**	**378,141**	**365,221**	**378,435**	**388,247**	**398,223**
Income from operating activities	**209,010**	**193,709**	**212,221**	**217,141**	**225,587**	**233,942**
Loss on derecognition of property, plant and equipment	5,826	4,720	1,920	6,064	6,125	6,187
Interest income	(1,288)	(1,603)	(1,482)	(1,898)	(1,827)	(2,073)
Interest expense	64,331	69,574	71,554	74,114	75,631	80,777
Income before taxes	**140,141**	**121,018**	**140,229**	**138,861**	**145,658**	**149,051**
Payments in lieu of income taxes	(18,027)	(8,241)	(16,461)	(23,981)	(26,660)	(27,965)
Net income	**122,114**	**112,777**	**123,768**	**114,880**	**118,998**	**121,086**

Exhibit C2 - Electricity Distribution Operations - Statement of Financial Position - MIFRS ($000s)

	2018	2019	2020	2021	2022	2023
Assets						
Current assets						
Accounts receivable	493,197	511,297	519,617	529,857	539,854	550,160
Inventory	17,877	19,595	18,125	17,538	17,881	17,809
Prepaid expenses	9,737	9,910	8,977	9,131	9,282	9,547
Due from related parties	4,668	6,788	5,518	6,880	6,357	7,193
	525,479	**547,590**	**552,237**	**563,406**	**573,374**	**584,709**
Non-current assets						
Net fixed assets	3,083,497	3,338,895	3,561,670	3,744,964	3,928,787	4,099,395
Goodwill	704,890	704,890	704,890	704,890	704,890	704,890
Right of use asset	—	13,430	11,930	10,443	9,307	8,507
Investment in subsidiary	3,963	3,963	3,963	3,963	3,963	3,963
Regulatory assets	20,406	80,057	107,609	125,433	142,694	159,558
	3,812,756	**4,141,235**	**4,390,062**	**4,589,693**	**4,789,640**	**4,976,313**
Total assets	**4,338,235**	**4,688,825**	**4,942,299**	**5,153,099**	**5,363,015**	**5,561,021**
Liabilities						
Current liabilities						
Bank indebtedness	145,704	62,329	192,871	123,295	339,513	170,428
Accounts payable and accrued liabilities	360,341	389,937	390,218	397,834	404,610	410,063
Current portion of lease liability	—	1,349	1,392	1,080	768	818
Current portion of legal and environmental provisions	862	862	862	862	862	862
Customer deposits liability	101,339	104,379	107,510	110,735	114,057	117,479
Other liabilities	6,967	7,072	7,178	2,932	2,976	3,020
Loan payable to parent	—	40,000	110,000	150,000	—	316,102
Due to related parties	33,345	33,939	30,658	31,271	31,787	32,695
Income tax payable	1,573	—	3,099	4,643	5,872	—
Notes payable to province of Ontario	1,546	—	—	—	—	—
Transition cost liability	2,022	6,792	—	—	—	—
	653,698	**646,659**	**843,787**	**822,653**	**900,446**	**1,051,467**
Non-current liabilities						
Lease liability	—	16,078	14,687	13,607	12,839	12,021
Deferred revenues	325,608	430,263	512,097	574,023	636,701	680,747
Long-term loan from parent	1,631,102	1,791,102	1,681,102	1,781,102	1,781,102	1,715,000
Deferred tax liability	21,029	55,108	88,936	113,764	132,866	151,182
Employee future benefits	67,142	69,414	71,775	74,215	76,738	79,347
Legal and environmental provisions	109	109	109	109	109	109
Other long-term liabilities	4,354	4,354	4,354	4,354	4,354	4,354
	2,049,345	**2,366,430**	**2,373,059**	**2,561,174**	**2,644,710**	**2,642,760**
Total liabilities	**2,703,043**	**3,013,088**	**3,216,846**	**3,383,827**	**3,545,156**	**3,694,227**
Shareholders' equity						
Share capital	681,677	681,677	681,677	681,677	681,677	681,677
Accumulated other comprehensive income	(2,242)	(2,242)	(2,242)	(2,242)	(2,242)	(2,242)
Contributed surplus	738,720	738,720	738,720	738,720	738,720	738,720
Retained earnings	217,037	257,582	307,298	351,117	399,704	448,639
Total shareholder's equity	**1,635,192**	**1,675,737**	**1,725,453**	**1,769,272**	**1,817,859**	**1,866,794**
Total liabilities and shareholder's equity	**4,338,235**	**4,688,825**	**4,942,299**	**5,153,099**	**5,363,015**	**5,561,021**

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Exhibit C3 - Electricity Distribution Operations - Statement of Cash Flows - MIFRS ($000s)

	2018	2019	2020	2021	2022	2023
Operating Activities						
Net income for the period	122,114	112,777	123,768	114,880	118,998	121,086
Add (deduct) non-cash items:						
Depreciation and amortization	131,637	142,331	153,969	164,295	171,343	175,472
Amortization of deferred revenue	(8,915)	(11,946)	(13,161)	(14,140)	(15,141)	(15,919)
Loss on sale and disposal of plant, property and equipment	5,826	4,720	1,920	6,064	6,125	6,187
Deferred payments in lieu of income taxes	33,609	34,079	33,828	24,828	19,102	18,315
Net change in deferred revenue	69,492	116,601	94,994	76,066	77,819	59,965
Net change in employee future benefits	2,370	2,272	2,360	2,440	2,523	2,609
Net change in other assets and liabilities	(55,460)	(48,270)	(38,786)	(23,465)	(18,665)	(27,665)
Cash from operating activities	**300,674**	**352,565**	**358,892**	**350,968**	**362,105**	**340,050**
Investing Activities Additions						
to fixed assets Additions to	(332,570)	(402,449)	(378,664)	(353,653)	(361,291)	(352,267)
right of use assets	—	(13,430)	1,500	1,487	1,137	799
Cash used in investing activities	**(332,570)**	**(415,879)**	**(377,165)**	**(352,165)**	**(360,154)**	**(351,468)**
Financing Activities						
Net change in customer deposits	9,794	3,040	3,131	3,225	3,322	3,422
Net change in capital leases	(15,882)	—	—	—	—	—
Net change in long-term borrowings	(36,109)	160,000	(110,000)	100,000	—	(66,102)
Net change in notes payable to province of Ontario	(4,558)	(1,546)	—	—	—	—
Net change in short term debt	(116,551)	—	—	—	—	—
Net change in lease liability	—	17,427	(1,349)	(1,392)	(1,080)	(768)
Net change in loan payable to parent	—	40,000	70,000	40,000	(150,000)	316,102
Dividends	(55,082)	(72,232)	(74,052)	(71,061)	(70,411)	(72,151)
Cash from (used in) financing activities	**(218,388)**	**146,689**	**(112,269)**	**70,773**	**(218,169)**	**180,503**
Increase/(decrease) in cash and cash equivalents	**(250,285)**	**83,375**	**(130,541)**	**69,576**	**(216,218)**	**169,085**
Cash and cash equivalents, beginning of period	**104,581**	**(145,704)**	**(62,329)**	**(192,871)**	**(123,295)**	**(339,513)**
Cash and cash equivalents (bank indebtedness), end of period	**(145,704)**	**(62,329)**	**(192,871)**	**(123,295)**	**(339,513)**	**(170,428)**

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Exhibit C4 - Electricity Distribution Operations Financial Results and Selected Metrics ($000s)

	2018	2019	2020	2021	2022	2023
IFRS Net Income	143,998	74,576	103,810	100,823	102,968	104,715
Modified IFRS Net Income	122,114	112,777	123,768	114,880	118,998	121,086
Debt (Funded Long-term Sources)	1,680,451	1,859,549	1,749,935	1,850,337	1,851,112	1,786,159
Current Assets	525,479	547,590	552,237	563,406	573,374	584,709
Current Liabilities	653,698	646,659	843,787	822,653	900,446	1,051,467
Total Assets	4,338,235	4,688,825	4,942,299	5,153,099	5,363,015	5,561,021
Closing equity	1,635,192	1,675,737	1,725,453	1,769,272	1,817,859	1,866,794
Adjusted Funds From Operations (AFFO)	236,560	237,489	265,910	275,649	283,247	280,013
EBITDA	334,418	326,871	355,900	370,265	384,859	396,669
EBIT	211,696	196,486	215,092	220,110	228,657	237,116
Return on Closing Equity (MIFRS with ICM)	7.5%	6.7%	7.2%	6.5%	6.5%	6.5%
Adjusted Interest*	65,729	70,748	72,943	75,185	76,874	81,878
EBIT Interest Coverage	2.2:1	1.8:1	1.9:1	1.9:1	2.0:1	1.9:1
AFFO:Debt	13.0%	12.4%	13.7%	14.0%	12.9%	14.3%
AFFO: Capital Expenditures	0.7:1	0.6:1	0.7:1	0.8:1	0.8:1	0.8:1
Debt to Capital	50.7%	52.6%	50.4%	51.1%	50.5%	48.9%
AFFO: Interest	4.6:1	4.4:1	4.6:1	4.7:1	4.7:1	4.4:1

*Adjusted interest includes financing charges and 4% deemed interest on employee future benefits.

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